Steadman,Dixie L - KDP

From: Eissler,Annie A - KDP
Sent: Thursday, March 24, 2005 8:03 AM
To: Steadman,Dixie L - KDP
Subject: FW: FOIA request #05-026

-----Original Message-----
From: Olsen,Carol A - TMC
Sent: Wednesday, March 23, 2005 4:33 PM
To: Smiley,Debra L - KDP
Cc: Eissler,Annie A - KDP
Subject: RE: FOIA request #05-026

Hi, there will be two more fee computation sheets: One from Chuck Combs and possibly one from Fran Gebhardt.

We have a BPA contractor making the copies, does she need to log her time as well?

Thanks, Carol

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From: Smiley,Debra L - KDP
Sent: Thursday, March 10, 2005 10:46 AM
To: Olsen,Carol A - TMC
Cc: Eissler,Annie A - KDP
Subject: FW: FOIA request #05-026

Hi Carol. I have answers to your questions and have noted them below each question.
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From: Olsen,Carol A - TMC
Sent: Wednesday, March 09, 2005 2:15 PM
To: Smiley,Debra L - KDP
Cc: Eissler,Annie A - KDP
Subject: RE: FOIA request #05-026

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1. In the past I couldn't recall if my office made 3 sets of copies or I sent down one set and the FOIA group made the other Please remind me.

If no information is being redacted, you'll need to make 2 sets of the docs and send both to me. I send one to the requestor along with a letter signed by Annie and keep the other for the official file. If you're planning to redact info under one or more of the FOIA exemptions, I'll need a set of the original docs (clean and not redacted) and 2 sets of the redacted version -- one for the requestor and one for the official file.

2. Who calls Carol Opatrony with any questions we may have? Fran as the official or one of us? We have a couple clarifying Q's for Carol Op.

Fran as the AO should make the call if you need to clarify portions of her request.

3. Someone in my office, in passing, thought that there might be a fee level at which we need to call the FOIA requester and say, "Looks like we estimate that it will cost $X - do you still want to proceed with the FOIA?" - is that true? Do we need to estimate our fee amounts for that purpose? If so, when would you need that?

Ms. Opatrny indicated in her request that she was willing to pay fees associated with her

request. She did not indicate that she needed an estimate, nor did she set a ceiling. So, you need not call her.

Thanks, Carol

-----Original Message-----
From: Smiley,Debra L - KDP
Sent: Thursday, March 03, 2005 11:36 AM
To: Olsen,Carol A - TMC; Gebhardt,Frances L - TMC
Cc: Bennett,Barry - LC; McDaniel,Mary J - TMC; Paulsrude,Russell E - TMC; Jones,Yolonda L - TMC; Eissler,Annie A - KDP
Subject: RE: FOIA request - extension

We can do an extension, however,extensions are for 10 working days, not 20. The new due date is March 29. I'll get a letter out to the requestor late next week and "cc" you all on it.

-----Original Message-----
From: Olsen,Carol A - TMC
Sent: Thursday, March 03, 2005 11:11 AM
To: Smiley,Debra L - KDP; Gebhardt,Frances L - TMC
Cc: Bennett,Barry - LC; McDaniel,Mary J - TMC; Paulsrude,Russell E - TMC; Jones,Yolonda L - TMC
Subject: RE: FOIA request - extension
Importance: High

Hi, Debra - for FOIA request #05-026 myself and Mary met with Barry this morning to scope out what we need to provide and we are identifying the documents for the request, yet given workloads we would like to ask for an extension, which I understand is something that can be done easily. The documents would be due 3/15 and I understand that a 20 day extension is "typical". Fran is the Authorizing Official.

I am leading the charge for #3 and #4 of the letter from Carol Opatrny. I will ask Fran who she assigned #1 and #2 of the letter to so we can coordinate the extension - with them.

Who sends out notice of extension?

Thanks, Carol

-----Original Message-----
From: Olsen,Carol A - TMC
Sent: Monday, February 14, 2005 11:19 AM
To: Smiley,Debra L - KDP
Cc: Hargin,Cheryl D - TMF; Gebhardt,Frances L - TMC; Baskerville,Sonya L - LT
Subject: RE: FOIA request

I believe that Janie Selby or Fran Gebhardt need to be the Authorizing Official. I just got into the office, let me ask and then get back with you. Thanks, Carol

-----Original Message-----
From: Smiley,Debra L - KDP
Sent: Monday, February 14, 2005 10:26 AM
To: Olsen,Carol A - TMC
Cc: Hargin,Cheryl D - TMF; Gebhardt,Frances L - TMC; Baskerville,Sonya L - LT
Subject: FW: FOIA request
Importance: High

Carol - The FOIA request Sonya is referencing in this email has come in. I'm logging it

in today and our response deadline is March 15 (unless you end up needing the 10 working day extension allowed by FOIA). I'll prepare an acknowledgment letter for the requestor and get it out today with you listed as the Authorizing Official -- unless you want to list someone else as AO. I'll forward a copy of the request, a copy of our acknowledgement letter and a Computation Sheet (for you to track search/review hours so that we can assess fees) to you today. Is there anyone else in TBL that needs to be "cc'd" on this beside Cheryl, Sonya and Frances? Thanks!

-----Original Message-----
From: Baskerville,Sonya L - LT
Sent: Wednesday, February 02, 2005 4:40 PM
To: Olsen,Carol A - TMC
Cc: Gebhardt,Frances L - TMC; Hargin,Cheryl D - TMF; Eissler,Annie A - KDP; Smiley,Debra L - KDP
Subject: FW: FOIA request
Importance: High

Hey, Carol. I left you a voicemail also. Carol, et. al., we should expect to see one (maybe two) FOIA requests for (1) advanced funding agreements; possibly (2) current state of borrowing authority; and possibly (3) OATT service agreements for third AC capacity. The third is a "possible" because Carol Opatrny already has some of those, doesn't need others, and was going to inform Bill Pascoe (the other consultant) of that.

The other documents that Bill mentioned were documents related to our remaining borrowing authority. Carol is interested in learning about that also, but not necessarily interested in documents, so we may not see that on her request. Given the current sensitivities related to borrowing authority, we need to be sure not to divulge information that is not public information.

Annie and Debi, when this comes in, please let me know. I think Carol is the "Authorizing Official" and I will work with her, Carol Jacobson, and whoever else to review whatever needs reviewing or disclosure purposes. Thanks!

-----Original Message-----
From: Baskerville,Sonya L - LT
Sent: Tuesday, February 01, 2005 2:42 PM
To: 'pascoeenergy@aol.com'
Subject: FOIA request
Importance: High

Here's the link for the "how to" on a FOIA request. Pretty straightforward. If you have any questions, feel free to give me a call.

By the way, I just talked with Carol Opatrny about similar issues - she's going to give you a call.

Thanks.

http://www.bpa.gov/EBR/FOIA/howto.htm

Department of Energy

Official File

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

CORPORATE

March 10, 2005

In reply refer to: KDP-7

Opartny Consulting Inc.
Ms. Carol Close Opartny
18509 NE Cedars Drive
Battle Ground, WA 98604
(360) 666-8510

RE: FOIA Request #05-026

Dear Ms. Opartny:

I am writing regarding your Freedom of Information Act (FOIA) request #05-026. We are unable to meet the initial deadline for completion of this FOIA request; as permitted by statute; we will take a ten working-day extension of time in which to respond to your request. The extension will also provide us with enough time to collect and complete the review process of the materials gathered in response to your FOIA request. The new due date for this FOIA is March 29, 2005.

If you have any questions, please contact me at (503) 230-5110. Thank you for your patience.

Sincerely,

Annie Eissler

Annie Eissler
Freedom of Information Officer

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Official File

CORPORATE

March 26, 2005

In reply refer to: KDP-7

Ms. Carol Close Opatrny
Opatrny Consulting, Inc.
18509 NE Cedars Drive
Battle Ground, WA 98604
360-666-8510

RE: FOIA #05-026

Dear Ms. Opatrny:

This letter responds to your Freedom of Information Act request dated February 7, 2005, and logged in as request #05-026.

Enclosed in their entirety are the following documents in response to your request.

Customer	***Contract Number***
Snohomish PUD	DE-MS79-94BP94525 & Amendment No. 1
Tacoma Public Utilities	DE-MS79-94BP94524 & Amendment No. 1
Puget Sound Energy, Inc.	DE-MS79-94BP94521& Amendment No. 1
Seattle City Light	DE-MS79-94BP94522
Power Resources Cooperative	DE-MS79-94BP94523& Amendment No. 1
PacifiCorp	94628 & Amendment No. 1
Coral Power L.L.C.	00TX-10286 and Amendment No. 1, Exhibit A, Tables 3,4.
Morgan Stanley Capital Group Inc.	97TX-10031 and Amendment No. 1, Exhibit C, Tables 16 – 19
The City of Glendale	DE-MS79-87BP92412
The City of Burbank	DE-MS79-87BP92411
Transalta Energy Marketing (U.S.), Inc. – Temus	98TX-10172 and Amendment No. 1, Exhibit C, Table 12
Transcanada Power a division of Transcanada Energy LTD.	02TX-10882, Exhibit A, Table 1

Hermiston Power Partnership	98TX-10154
PacifiCorp	DE-MS79-94BP94285 and Revision No. 1 to Exhibit C
PacifiCorp	DE-MS79-94BP94332
PacifiCorp Power Marketing, INC.	00TX-10367, Revision No. 3 to Exhibit A, Tables 1, 5,8,9,10,11 and 12.
British Columbia Power Exchange Corporation	99TX-10251, Exhibit A, Tables 21,24 - 26, 29, 40, 41.
Bonneville Power Administration Power Business Line	96MS-95363, Exhibit C, Tables 17, 18, 21, 50, 51, 60.
Portland General Electric Company	DE-MS79-89BP92273
Portland General Electric Company	DE-MS79-878BP92340
Idaho Power Company	DE-MS79-91BP93094 and Revision No. 2 to Exhibit C.
PacifiCorp	DE-MS79-94BP94280 & Revision No. 3 to Exhibit C, Tables 53, 54.
PacifiCorp	DE-MS79-94BP94285
The City of Pasadena	DE-MS79-87BP92413
Riverside, California	DE-MS79-90BP92858
Riverside, California	DE-MS79-94BP93958
The City of Pasadena	DE-MS79-94BP93658
NOB to Big Eddy Summary	
Summary	
Summary	
Summary	

If you are dissatisfied with this determination, you may make an appeal within thirty (30) days of receipt of this letter to: Director, Office of Hearings and Appeals, Department of Energy, 1000 Independence Avenue SW, Washington, D.C. 20585. Both the envelope and the letter must be clearly marked "Freedom of Information Act Appeal".

In your original letter you agreed to pay fees to fulfill your request. Costs to complete your request totaled $2,134.06 for search, review and copy. You will be billed for this amount under separate cover by our accounting department.

Sincerely,

Annie Eissler
Freedom of Information Officer

Enclosures

Yes, we need the computation sheets with the two sets of responsive docs. We include fee information in the closing letter.

-----Original Message-----
From: Olsen,Carol A - TMC
Sent: Thursday, March 24, 2005 1:06 PM
To: Smiley,Debra L - KDP; Jones,Yolonda L - TMC
Cc: Eissler,Annie A - KDP
Subject: RE: FOIA request #05-026

Hopefully the last question: when do we send in our forms tracking our costs? Do you need the amounts for the outgoing letter? I'm still working a bit on it throughout the day and the attny (and the contractor as well).

Yo Yo - if you don't see a reply to this e-mail before you leave today could you call Debra for this question and the one below? Thanks, Carol

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From: Olsen,Carol A - TMC
Sent: Wednesday, March 23, 2005 4:33 PM
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Cc: Eissler,Annie A - KDP
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Smiley,Debra L - KDP

From: Olsen,Carol A - TMC
Sent: Tuesday, March 29, 2005 1:25 PM
To: Smiley,Debra L - KDP; Eissler,Annie A - KDP
Cc: Combs,Chuck - LT
Subject: FW: $ charged for FOIA 05-026

Importance: High

Here is Chuck's preliminary information. Chuck - they will also need your hourly rate increase by 16% to compute the total for the letter. Thanks, Carol

-----Original Message-----
From: Combs,Chuck - LT
Sent: Tuesday, March 29, 2005 12:56 PM
To: Olsen,Carol A - TMC
Subject: RE: $ charged for FOIA

30.96+16% = 59 11

3/24 - review documents 45 minutes
3/25 - review documents 1 hour

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From: Olsen,Carol A - TMC
Sent: Thursday, March 24, 2005 1:37 PM
To: Combs,Chuck - LT; Bennett,Barry - LC; Gebhardt,Frances L - TMC
Subject: FW: $ charged for FOIA

If you could tally up your time [when you are through] & $ on the computation sheet I sent you, Deb will need it before she sends out the letter on Tuesday. Thanks, Carol

-----Original Message-----
From: Olsen,Carol A - TMC
Sent: Thursday, March 24, 2005 1:29 PM
To: McDaniel,Mary J - TMC; Paulsrude,Russell E - TMC
Subject: $ charged for FOIA

Hi - please send your computation sheets to Deb. I'm not sending mine until my work is done tomorrow. Thanks, Carol

-----Original Message-----
From: Smiley,Debra L - KDP
Sent: Thursday, March 24, 2005 1:23 PM
To: Olsen,Carol A - TMC; Jones,Yolonda L - TMC
Cc: Eissler,Annie A - KDP
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COB to John Day Summary

AC COB S>N 2005		Contract Number	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180
	TPU	DE-MS79-94BP94524	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17
	SNO	DE-MS79-94BP94525	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17
	PSE	DE-MS79-94BP94521	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167
	SCL	DE-MS79-94BP94522	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67
	PRC	DE-MS79-94BP94523	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21

COB to John Day Summary

AC COB S>N 2005		Contract Number	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221
	TPU	DE-MS79-94BP94524	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21
	SNO	DE-MS79-94BP94525	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21
	PSE	DE-MS79-94BP94521	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204
	SCL	DE-MS79-94BP94522	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82
	PRC	DE-MS79-94BP94523	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221
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	SNO	DE-MS79-94BP94525	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21
	PSE	DE-MS79-94BP94521	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204
	SCL	DE-MS79-94BP94522	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82
	PRC	DE-MS79-94BP94523	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221
	TPU	DE-MS79-94BP94524	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21
	SNO	DE-MS79-94BP94525	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21
	PSE	DE-MS79-94BP94521	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204
	SCL	DE-MS79-94BP94522	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82
	PRC	DE-MS79-94BP94523	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221
	TPU	DE-MS79-94BP94524	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21
	SNO	DE-MS79-94BP94525	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21
	PSE	DE-MS79-94BP94521	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204
	SCL	DE-MS79-94BP94522	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82
	PRC	DE-MS79-94BP94523	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
AC Intertie													
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71
AC Participants													
	PGE	DE-MS79-87BP92340	434	354	354	354	434	434	434	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	180	180	180	221	221	221	221	221	221	221
	TPU	DE-MS79-94BP94524	21	17	17	17	21	21	21	21	21	21	21
	SNO	DE-MS79-94BP94525	21	17	17	17	21	21	21	21	21	21	21
	PSE	DE-MS79-94BP94521	204	167	167	167	204	204	204	204	204	204	204
	SCL	DE-MS79-94BP94522	82	67	67	67	82	82	82	82	82	82	82
	PRC	DE-MS79-94BP94523	25	21	21	21	25	25	25	25	25	25	25

Big Eddy to NOB

DC NOB N>S 2005

	Contract Number	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
Burbank	DE-MS79-87BP92411	20	20	20	20	40	40	40	40	40	40	20	20	20	20	20	20	40	40	40	40	40	40	20	20	20	20	20	40	40
Glendale	DE-MS79-87BP92412	10	10	10	10	20	20	20	20	20	20	10	10	10	10	10	10	20	20	20	20	20	20	10	10	10	10	10	20	20
Pasadena	DE-MS79-87BP92413	6	6	6	6	12	12	12	12	12	12	6	6	6	6	6	6	12	12	12	12	12	12	6	6	6	6	6	6	12	12
Pasadena	DE-MS79-94BP93658					15	15	15	15	15								15	15	15	15	15								15	15
Riverside	DE-MS79-90BP92858	16	16	16	16	23	23	23	23	23	23	16	16	16	16	16	16	23	23	23	23	23	23	16	16	16	16	16	16	23	23
Riverside	DE-MS79-94BP93958	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60
PBL (Table 50)	96MS-95363	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100									
Hermiston, Calpine	98TX-10154			228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650						
Powerex Corp	99TX-10251	408	408	408	408	408	408	408	408	408	408	408	408																		
Powerex Corp	99TX-10251	49	49	49	49	49	49	49	49	49	49	49	49																		
Powerex Corp	99TX-10251						150	150	150	150	150	150	150	150	150	150	150	150													
Powerex Corp	99TX-10251	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Morgan Stanley	97TX-10031 Ex C Table 16	50	50	50	50	50	50	50	50	50	50	50	50																		
Morgan Stanley	97TX-10031 Ex C Table 17	50	50	50	50	50	50	50	50	50	50	50	50																		
Morgan Stanley	97TX-10031 Ex C Table 18													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Morgan Stanley	97TX-10031 Ex C Table 19													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Coral Power	00TX-10286 Table 3													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Coral Power	00TX-10286 Table 4													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Idaho Power Company	DE-MS79-91BP93094	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005

	Contract Number	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Burbank	DE-MS79-87BP92411	40	40	40	40	20	20	20	20	20	20																				
Glendale	DE-MS79-87BP92412	20	20	20	20	10	10	10	10	10	10																				
Pasadena	DE-MS79-87BP92413	12	12	12	12	6	6	6	6	6	6																				
Pasadena	DE-MS79-94BP93658	15	15	15								15	15	15	15	15								15	15	15	15	15			
Riverside	DE-MS79-90BP92858	23	23	23	23	16	16	16	16	16	16	23	23	23	23	23	23	16	16	16	16	16	16	23	23	23	23	23	23	16	16
Riverside	DE-MS79-94BP93958	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15
PBL (Table 50)	96MS-95363	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172																														
Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251	200	200	200	200	200	200	200	200	200	200	200	200	200	200																
Morgan Stanley	97TX-10031 Ex C Table 16																														
Morgan Stanley	97TX-10031 Ex C Table 17																														
Morgan Stanley	97TX-10031 Ex C Table 18	50	50	50	50	50	50																								
Morgan Stanley	97TX-10031 Ex C Table 19	50	50	50	50	50	50																								
Coral Power	00TX-10286 Table 3	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Coral Power	00TX-10286 Table 4	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Idaho Power Company	DE-MS79-91BP93094	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005

	Contract Number	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
Burbank	DE-MS79-87BP92411																														
Glendale	DE-MS79-87BP92412																														
Pasadena	DE-MS79-87BP92413																														
Pasadena	DE-MS79-94BP93658					15	15	15	15	15								15	15	15	15	15								15	15
Riverside	DE-MS79-90BP92858	16	16	16	16	23	23																								
Riverside	DE-MS79-94BP93958	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60
PBL (Table 50)	96MS-95363	24	24	24	24	24	24																								
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172																														
Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Morgan Stanley	97TX-10031 Ex C Table 16																														
Morgan Stanley	97TX-10031 Ex C Table 17																														
Morgan Stanley	97TX-10031 Ex C Table 18																														
Morgan Stanley	97TX-10031 Ex C Table 19																														
Coral Power	00TX-10286 Table 3																														
Coral Power	00TX-10286 Table 4																														
Idaho Power Company	DE-MS79-91BP93094	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3											
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005	Contract Number	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Burbank	DE-MS79-87BP92411																														
Glendale	DE-MS79-87BP92412																														
Pasadena	DE-MS79-87BP92413																														
Pasadena	DE-MS79-94BP93658	15	15	15								15	15	15	15	15								15	15	15	15	15			
Riverside	DE-MS79-90BP92858																														
Riverside	DE-MS79-94BP93958	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60				
PBL (Table 50)	96MS-95363																														
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172																														
Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Morgan Stanley	97TX-10031 Ex C Table 16																														
Morgan Stanley	97TX-10031 Ex C Table 17																														
Morgan Stanley	97TX-10031 Ex C Table 18																														
Morgan Stanley	97TX-10031 Ex C Table 19																														
Coral Power	00TX-10286 Table 3																														
Coral Power	00TX-10286 Table 4																														
Idaho Power Company	DE-MS79-91BP93094																														
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005																						
		Contract Number	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
	Burbank	DE-MS79-87BP92411																					
	Glendale	DE-MS79-87BP92412																					
	Pasadena	DE-MS79-87BP92413																					
	Pasadena	DE-MS79-94BP93658																					
	Riverside	DE-MS79-90BP92858																					
	Riverside	DE-MS79-94BP93958																					
	PBL (Table 50)	96MS-95363																					
	PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	TransAlta	98TX-10172																					
	Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Morgan Stanley	97TX-10031 Ex C Table 16																					
	Morgan Stanley	97TX-10031 Ex C Table 17																					
	Morgan Stanley	97TX-10031 Ex C Table 18																					
	Morgan Stanley	97TX-10031 Ex C Table 19																					
	Coral Power	00TX-10286 Table 3																					
	Coral Power	00TX-10286 Table 4																					
	Idaho Power Company	DE-MS79-91BP93094																					
	PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	486	486	258	258	258	258	258	258	258	258	258
PowerEx(What happened to Table 43?)	99TX-10251	0	0	50	50	50	50	50	50	50	50	50
PowerEx	99TX-10251	200	200	200	200	200	200	200	200	200	200	200
PowerEx	99TX-10251	63	63	63	63	63	63	63	63	63	63	63
PowerEx	99TX-10251	73	73	73	73	73	73	73	73	73	73	73
PowerEx	99TX-10251	42	42	42	42	42	42	42	42	42	42	42
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1	95	95	95	95	95	95	95	95	95	95	95
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5							100	100	100	100	100
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A	50	50	50	50	50	50	50	50	50	50	50
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882	20	20	20	20	20	20	20	20	20	20	20
TransCanada Power	02TX-10882	30	30	30	30	30	30	30	30	30	30	30
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	753	753	753	753	753	753	753	753	753	753	753
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	383	383	383	383	383	383	383	383	383	383	383
TCL	DE-MS79-94BP94524	36	36	36	36	36	36	36	36	36	36	36
SNO	DE-MS79-94BP94525	37	37	37	37	37	37	37	37	37	37	37
PSP&L	DE-MS79-94BP94521	354	354	354	354	354	354	354	354	354	354	354
SCL	DE-MS79-94BP94522	142	142	142	142	142	142	142	142	142	142	142
PNGC	DE-MS79-94BP94523	44	44	44	44	44	44	44	44	44	44	44

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	258	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	50	50	50	50	50	50	50	0	0	0	0
PowerEx	99TX-10251	200	200	200	200	200	200	200	200	200		
PowerEx	99TX-10251	63	63	63	63	63	63	63	63	63		
PowerEx	99TX-10251	73	73	73	73	73	73	73	73	73		
PowerEx	99TX-10251	42										
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1	95	95	95	95	95	95	95	95	95	95	95
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5	100	100	100	100	100	100	100				
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8		75	75	75	75	75	75	75	75	75	75
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9		42	42	42	42	42	42	42	42	42	42
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A	50										
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A		8	8	8	8	8	8	8	8	8	8
TransCanada Power	02TX-10882	20	20	20	20							
TransCanada Power	02TX-10882	30	30	30	30							
Transalta Energy	98TX-10172								42	42	42	42
PGE	DE-MS79-87BP92340	753	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	383	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	36	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	37	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	354	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	142	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	44	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1	95	95	95	95	95	95					
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8	75	75									
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9	42	42									
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A	8	8									
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172	42	42	42	42	42	42	42	42			
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180							
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150										
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363											
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363											
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
PBL	96MS-95363	50	50	50	50	50	50			
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363									
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251									
PowerEx	99TX-10251									
PowerEx	99TX-10251									
PowerEx	99TX-10251									
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1									
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12									
PacifiCorp Power Mkting	00TX-10367 Table 5									
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8									
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9									
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A									
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A									
TransCanada Power	02TX-10882									
TransCanada Power	02TX-10882									
Transalta Energy	98TX-10172									
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

SEP 26 1994

In reply refer to: PMT

Amendatory Agreement No. 1
Contract No. DE-MS79-94BP94525

Mr. John F. Spencer
General Manager
Public Utility District No. 1 of
Snohomish County, Washington
2320 California Street
Everett, WA 98201

Dear Mr. Spencer:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and Public Utility District No. 1 of Snohomish County Washington (Snohomish), a municipal corporation operating and existing under the laws of the State of Washington, to amend Contract No. DE-MS79-94BP94525 (Capacity Ownership Agreement), executed by Snohomish on September 23, 1994. This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and Snohomish agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) Snohomish may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Snohomish. Snohomish agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to Snohomish under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) Snohomish hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. Snohomish does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but

not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to Snohomish consistent with the above.

Snohomish and Bonneville agree to negotiate in good faith the terms and conditions under which Snohomish shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Snohomish or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only Snohomish)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to Snohomish shall mean Snohomish or its designee. Any such designee shall be identified in writing by Snohomish to Bonneville. Only one entity may submit schedules on Snohomish's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to Snohomish, please sign and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Walter E. Pollock
Group Vice President, Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY

By _____

Name Mark A. Schinman
(Print/Type)

Title Deputy General Manager

Date October 25, 1994

Effective Date October 25, 1994

(PMLAN-W:\PMT\CONTRACT\LTR_AGMT\94525AM1.DOC)

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94525

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Snohomish's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY WASHINGTON (Snohomish), a municipal corporation operating and existing under the laws of the state of Washington. Each of Bonneville and Snohomish is sometimes referred to individually in this Agreement as "Party"; Bonneville and Snohomish are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Seattle executed a Memorandum of Understanding, DE-MS79-92BP93479, dated September 18, 1991, which, among other things, sets forth the principles for Snohomish's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Snohomish are executing Contract No. DE-MS79-94BP93999 to provide Snohomish with, among other things, network wheeling between the John Day Substation and Snohomish's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Snohomish agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Snohomish's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this

Agreement, entered into by each Capacity Owner (other than Snohomish) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by Capacity Owners (other than Snohomish) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Snohomish pursuant to this Agreement, which percentage is determined by dividing Snohomish's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Snohomish pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Snohomish pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective

Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for

Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Snohomish's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Snohomish to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Snohomish.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1)

simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Snohomish for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Snohomish for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Snohomish's Capacity

Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement, interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Snohomish pursuant to this Agreement, which percentage is determined by dividing Snohomish's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Snohomish's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Snohomish.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Snohomish until payment is made by Snohomish pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Snohomish pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Snohomish written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and

obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Snohomish pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Snohomish, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Snohomish purchases from Bonneville and Bonneville sells to Snohomish the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, Snohomish shall notify Bonneville in writing of Snohomish's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Snohomish shall have the right to utilize its Scheduling Share pursuant to the paragraph Snohomish elects. Prior to Bonneville's receipt of such notification, Snohomish shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Snohomish fails to make an election within the prescribed time period, Snohomish shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Snohomish shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Snohomish does not own at the California-Oregon border or for which transmission Snohomish receives any revenue that would be reportable in Snohomish's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Snohomish's Scheduling Share is not fully utilized by Snohomish in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Snohomish's Scheduling Share for such hour but no longer than such hour. Snohomish shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Snohomish's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Snohomish has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Snohomish's Scheduling Share. In return for Snohomish's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Snohomish

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A,

or its successor to other entities in such hour, and (2) the ratio of Snohomish's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Snohomish's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Snohomish's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC

Intertie Operational Transfer Capability such that Snohomish's Scheduling Share for such hour is less than the MW amount of the aggregate of Snohomish's net firm transactions identified by Snohomish to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Snohomish's firm transactions that equals the difference between Snohomish's Scheduling Share for such hour and the MW amount of the aggregate of Snohomish's firm transactions for such hour up to, but not in excess of, Snohomish's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Snohomish is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Snohomish shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Snohomish pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for

Bonneville's firm power and energy sales and exchange transactions

(iii) Bonneville shall not be obligated to provide such wheeling to Snohomish pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Snohomish or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Snohomish shall identify such firm transaction to Bonneville. Snohomish shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Snohomish's contract for such firm transaction (after information considered proprietary by Snohomish has been redacted by Snohomish). Bonneville shall review such contract to verify that the transaction is firm. If Snohomish and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Snohomish retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Snohomish may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Snohomish. Snohomish shall have no obligation under this Agreement to make available to Bonneville any portion of Snohomish's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Snohomish's Scheduling Share without Snohomish's prior consent.

(B) Snohomish hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Snohomish with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Snohomish shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Snohomish uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Snohomish (and only Snohomish) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Snohomish's Scheduling Share for such hour. The MW amount of Snohomish's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Snohomish's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Snohomish shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Snohomish on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Snohomish of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Snohomish no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Snohomish no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Snohomish shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Snohomish shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Snohomish shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts"

shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Snohomish's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Snohomish's schedule exceeds Snohomish's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Snohomish information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Snohomish in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Snohomish's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Snohomish's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Snohomish may elect to acquire a share of such Upgrade in an amount up to Snohomish's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Snohomish shall notify Bonneville in writing of Snohomish's decision regarding such acquisition. If Snohomish elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Snohomish's notice to Bonneville shall include the percentage of such Upgrade that Snohomish elects to acquire (Acquisition Percentage). If Snohomish fails to notify Bonneville within such 100-day period, Snohomish shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Snohomish elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Snohomish shall be Snohomish's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Snohomish shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Snohomish's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Snohomish and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Snohomish and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Snohomish may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Snohomish such portion of the Unacquired Share as has been apportioned to Snohomish pursuant to the Apportionment, and Bonneville shall offer to Snohomish such portion of the Unacquired Share.

(2) If Bonneville does not receive from Snohomish and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Snohomish and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = (A ÷ B) x C

where: A = Snohomish's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Snohomish's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Snohomish shall notify Bonneville in writing of Snohomish's decision regarding acquisition of the Additional Share Offered. If Snohomish fails to notify Bonneville within such 30-day period, Snohomish shall be deemed to have elected not to acquire any of the Additional Share Offered. If Snohomish elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Snohomish shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Snohomish elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Snohomish with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Snohomish pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Snohomish shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Snohomish has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Snohomish's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Snohomish's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Snohomish to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Snohomish in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Snohomish to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Snohomish's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Snohomish of the entire Agreement and of all of Snohomish's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Snohomish of this Agreement or of any of Snohomish's rights under this Agreement as security for any indebtedness, whether present or future, of Snohomish pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Snohomish and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Snohomish has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Snohomish shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Snohomish transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Snohomish shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Snohomish's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Snohomish in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Snohomish in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time

during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Snohomish's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Snohomish based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Snohomish have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Snohomish pursuant to this subsection 7(d) shall not be payable by Snohomish pursuant to this Agreement.

(e) Bonneville shall provide Snohomish notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on Snohomish's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Snohomish's interests to the extent such interests have been expressed to Bonneville in writing.

8. **EXISTING AGREEMENTS**

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Snohomish's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Snohomish's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Snohomish's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Snohomish hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. **PAYMENT PROVISIONS**

As full compensation for their respective payment obligations under this Agreement, Snohomish shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Snohomish in accordance with the provisions of this section 9.

(a) **Lump Sum Payment**

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Snohomish for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as

described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Snohomish shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Snohomish agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Snohomish, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Snohomish shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may

mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Snohomish, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Snohomish agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Snohomish pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Snohomish pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville,

Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Snohomish a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Snohomish shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect

to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Snohomish, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Snohomish agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be

deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors

in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Snohomish pursuant to paragraph 9(a)(1), Bonneville shall bill Snohomish on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Snohomish shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate

Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such

terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Snohomish pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Snohomish on the monthly power bill, and Snohomish shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs,

and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Snohomish the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to

section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Snohomish written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Snohomish an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to

Snohomish on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Snohomish shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Snohomish an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to Snohomish on the monthly power bill the difference between such

actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Snohomish shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Snohomish pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Snohomish or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Snohomish on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Snohomish shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Snohomish the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Snohomish an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast

Reinforcement Cost, Bonneville shall bill Snohomish such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Snohomish shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Snohomish an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Snohomish such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Snohomish shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Snohomish pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Snohomish for wheeling provided pursuant to section 3(b)(1)(C)(i) on Snohomish's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Snohomish shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Snohomish shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Snohomish's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Snohomish pursuant to section 4 without incurring any liability to Snohomish therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Snohomish of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Snohomish makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Snohomish shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to

participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Snohomish shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Snohomish pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Snohomish pursuant to this Agreement; provided, however that Snohomish's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Snohomish pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Snohomish pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Snohomish, in a lump sum, any refund due to Snohomish pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Snohomish pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Snohomish under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Snohomish by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the

order of Snohomish, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Snohomish from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Snohomish's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Snohomish pursuant to this Agreement, Snohomish shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Snohomish and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Snohomish's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Snohomish's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Snohomish's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Snohomish's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11 REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Snohomish in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Snohomish of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Snohomish for purposes of effectuating remedial actions pursuant to this section.

(b) Snohomish's Responsibilities

(1) Snohomish shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Snohomish's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan

referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm Snohomish's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Snohomish shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Snohomish's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Snohomish pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Snohomish on Snohomish's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Snohomish shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Snohomish's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Snohomish and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Snohomish pursuant to subsection 11(b).

12 CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Snohomish may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Snohomish fails to appoint a representative to the Committee, Snohomish waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Snohomish hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Assistant General Manager for Rates and Resources

Alternate: Manager of Power Supply

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if

appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Snohomish, change the

designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. **OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN**

(a) The provisions of this section shall become effective commencing August 1, 1995, provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Snohomish, and Snohomish shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the

fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year

to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Snohomish and Capacity Owners other than Snohomish and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the

representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested; 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or

forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such

written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d) Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's

rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any

actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project, provided, however, that, without limiting any of Snohomish's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Snohomish and Capacity Owners other than Snohomish regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l)

through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Snohomish's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Snohomish is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Snohomish shall act through the Committee. Each of Bonneville and Snohomish agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to

the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville

written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Snohomish, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to

the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Snohomish each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those

parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Snohomish shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Snohomish its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners.

The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Snohomish or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Snohomish pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such

project; provided, however, that, without limiting any of Snohomish's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the

Committee or Snohomish, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number

of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and

information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into

consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Snohomish and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. **AUDIT RIGHTS**

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Snohomish pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Snohomish pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Snohomish or any Capacity Owner other than Snohomish for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for

such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Snohomish a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Snohomish a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Snohomish as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Snohomish's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Snohomish.

(f) If an audit report provided to Bonneville by Snohomish pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Snohomish a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Snohomish a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Snohomish as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Snohomish's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Snohomish; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Snohomish shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Snohomish chooses not to participate in any audit undertaken by the Committee, then Snohomish shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and

Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Snohomish of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Snohomish is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Snohomish's books, records, and documents that directly pertain to the revenue reportable in Snohomish's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Snohomish shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Snohomish is required by regulatory authority to purchase

or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Snohomish has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Snohomish or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Snohomish at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Snohomish may, within 90

days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Snohomish may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Snohomish may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Snohomish's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Snohomish has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Snohomish's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Snohomish's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Snohomish' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Snohomish's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Snohomish of the amount of the Refunded Lump Sum Payment.

If Snohomish elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to Snohomish and Capacity Owners other than Snohomish, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Snohomish or any Capacity Owner other than Snohomish.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Snohomish may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Snohomish may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Snohomish may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Snohomish's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Snohomish has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Snohomish's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + R = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Snohomish of the amount of Refunded Lump Sum Payment.

If Snohomish elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Snohomish and Capacity Owners other than Snohomish, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Snohomish or any Capacity Owner other than Snohomish.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Snohomish, and Capacity Owners other than Snohomish shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Snohomish in substantially the same position with respect to Snohomish's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the

expiration of the AC-93 rate. Bonneville, Snohomish, and Capacity Owners other than Snohomish shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Snohomish, and Capacity Owners other than Snohomish reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Snohomish, and Capacity Owners other than Snohomish do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Snohomish and Capacity Owners other than Snohomish and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Snohomish, and Capacity Owners other than Snohomish are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Snohomish may elect, within 6 months of any of the foregoing events, to terminate this

Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Snohomish's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Snohomish elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Snohomish shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Snohomish's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Snohomish a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Snohomish's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Snohomish's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Snohomish pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Snohomish to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each

monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Snohomish of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Snohomish's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Snohomish fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Snohomish shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period,

Bonneville and Snohomish shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Snohomish and Capacity Owners other than Snohomish. If Bonneville and Snohomish do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Snohomish, and Snohomish shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Snohomish's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and

section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Snohomish and Capacity Owners other than Snohomish.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and Snohomish agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be

applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. **NOTICES**

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) Amendments

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) Entire Agreement

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Snohomish shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Snohomish an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Snohomish during the development or consideration of any offer to any Capacity Owner other than

Snohomish to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate

set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Snohomish is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Snohomish's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Snohomish acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September 27, 1994

Date September 27, 1994

Public Utility District No. 1 of Snohomish County

By John F Spencer

/s/ JOHN F. SPENCER

Name John Spencer
(Print/Type)

Title General Manager

General Manager

Date 9/23/94

September 23, 1994

Effective Date September 27, 1994

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rate transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridi

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment, if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$XXX)} * \%}{725\ \text{MW} * \#\ \text{months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	42 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

Facilities whose costs will be adjusted using change Between Estimate and Actual		($ in Thousands) (1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Snohomish's Capacity Ownership Share	=	42 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$9,030,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Snohomish. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Snohomish's Capacity Ownership Share	=		42 MW
2.	Adjusted Capacity Ownership Price	X	$	
3.	Adjusted Lump Sum Payment[1]	=		
4.	Initial Lump Sum Payment	–		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Snohomish	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Snohomish	=		

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Snohomish receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Snohomish's Capacity Ownership Share	=		42 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Snohomish	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Snohomish	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Snohomish receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Snohomish receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Snohomish receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Snohomish's schedules for transactions transmitted on Snohomish's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Snohomish's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		
6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.		
For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Snohomish, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Snohomish and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Snohomish and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Snohomish or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Snohomish or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Snohomish and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Snohomish has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Snohomish shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Snohomish shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Snohomish agrees as follows:

(1) Snohomish shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Snohomish shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Snohomish shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Snohomish shall, in all solicitations or advertisements for employees placed by or on behalf of Snohomish, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Snohomish shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Snohomish's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Snohomish shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Snohomish shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Snohomish shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Snohomish's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Snohomish is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Snohomish may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Snohomish as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Snohomish shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Snohomish shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Snohomish becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Snohomish may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Snohomish certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Snohomish agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Snohomish agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Snohomish to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Snohomish hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Snohomish further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Snohomish's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Snohomish shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Snohomish acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Snohomish agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Snohomish agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Snohomish and Bonneville shall, in concert with the Capacity Owners other than Snohomish, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Snohomish pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Snohomish shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2			
C. AFUDC				
AFUDC of Replacements and Reinforcements	3			
D. Interest				
Interest Cost of Replacements and Reinforcements	4			
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5			

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1			
B. Other PNW AC Intertie costs	2			
C. Total Other Costs	3			

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1			
Total contracts and rates cost from rate case	2			
Contracts and rates cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5			
Contracts and rates indirect costs	6			
Contracts and rates overhead costs	7			
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8			
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9			

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1			
Total power scheduling cost from rate case	2			
Power scheduling cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Power Scheduling Costs				
Power scheduling direct costs	5			
Power scheduling indirect costs	6			
Power scheduling overhead costs	7			
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8			
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9			

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2			
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	( )	( )	( )
D. End of Term Costs	4			

Snohomish's Initial Transaction with California Utility

Name of parties: Snohomish / Sacramento Municipal Utility District

Term of Contract: September 30, 2007

Date of Execution: May 26, 1993

Amount of Transaction (MW): 42 MW

Amendment No. 3
Contract No. DE-MS79-94BP-94523

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

POWER RESOURCES COOPERATIVE

(Formerly PACIFIC NORTHWEST GENERATING COOPERATIVE)

This AMENDMENT to the PNW AC Intertie Capacity Ownership Agreement, Contract Number 94PB-94523, (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and Power Resources Cooperative, formerly known as Pacific Northwest Generating Cooperative (Customer). The Customer and BPA are sometimes referred to individually as "Party", and collectively as "Parties" as the context suggests below.

This Amendment No. 3 (Amendment) to the Agreement between BPA and the Customer acknowledges that on March 7, 1996, amended articles of incorporation were filed by Customer with the Secretary of State of Oregon formally changing its name to Power Resources Cooperative (PRC).

BPA and the Customer agree:

1. **EFFECTIVE DATE**
This Amendment shall take effect on the date executed by the Parties (Effective Date).

2. **AMENDMENT OF AGREEMENT**
BPA and the Transmission Customer wish to amend the Agreement as follows:

   (a) All references in the Agreement to "Pacific Northwest Generating Cooperative" or "PNGC" are hereby replaced with "Power Resources Cooperative."

3. **OTHER TERMS AND CONDITIONS UNAFFECTED**
The Parties agree that all other terms and conditions of the Agreement are unaffected by this Amendment.

4. **SIGNATURES**

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

POWER RESOURCES COOPERATIVE

By Joseph W. Nadal, Jr.

Name Joseph W. Nadal, Jr.
(Print/Type)

Title Senior Vice President

Date 11/30/2000

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Thomas M. Noguchi
Sr. Transmission Account Executive

Name Thomas M. Noguchi
(Print/Type)

Date 11/29/2000

12-04-00P02:33 RCVD

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Amendatory Agreement No. 2 to
Contract No. DE-MS79-94BP94523

AMENDATORY AGREEMENT
to the
PACIFIC NORTHWEST AC INTERTIE
CAPACITY OWNERSHIP AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFIC NORTHWEST GENERATING COOPERATIVE

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This AMENDATORY AGREEMENT is executed as of February 5, 1997 by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (hereinafter referred to as "BPA") and the PACIFIC NORTHWEST GENERATING COOPERATIVE (hereinafter referred to as "PNGC"), an Oregon cooperative corporation. The PNGC and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

W I T N E S S E T H :

WHEREAS the Parties on September 27, 1994, entered into the Pacific Northwest AC Intertie Capacity Ownership Agreement, Contract No. DE-MS79-94BP94523 (Agreement); and

WHEREAS the Parties on September 30, 1994, entered into Amendatory Agreement No. 1 to the Agreement which revised subsection 3(b)(2); and

WHEREAS the Federal Energy Regulatory Commission (FERC) has issued Order No. 888, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities and Transmitting Utilities;" and

WHEREAS the Parties desire to amend the Agreement so as to comply with such Order No. 888 and 889.

NOW, THEREFORE, the Parties agree as follows:

1. **DEFINITIONS**

Capitalized terms used in this Amendatory Agreement, unless otherwise defined herein, have the respective meanings set forth for such terms in the Agreement.

2. **AMENDMENT OF AGREEMENT**

Subsection 3(b) of the Agreement is deleted in its entirety and the following is inserted in lieu thereof:

(b) **Right to Wheel for Third Parties**

The PNGC may use its Scheduling Share to transmit any and all power and energy whether or not such power or energy is owned by PNGC. The PNGC shall have no obligation under this Agreement to make available to BPA any portion of PNGC's Scheduling Share which is unused in any hour, and BPA shall not schedule over PNGC's Scheduling Share without PNGC's prior written consent.

BPA shall treat all scheduling information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of FERC's regulations.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendatory Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Thomas M. Noguchi
Senior Account Executive

Name Thomas M. Noguchi
(Print/Type)

Date 2/3/97

PACIFIC NORTHWEST GENERATING COOPERATIVE

By David E. Piper

Name David E. Piper
(Print/Type)

Title President and CEO

Date 2/5/97

(HQ5F01-TMC-W:\MCP\TMC\CT\94523.DOC)

PNGC

Pacific Northwest Generating Cooperative

"Partners in Power Management"

February 7, 1997

Tom Noguchi
Customer Account Executive
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Dear Tom,

Here is a copy of the executed Capacity Ownership Agreement, Contract No. DE-MS79-94BP94523. Thank you for your help.

Sincerely,

Aleka U. Kitchen
Senior Power Management Specialist

Enclosure

711 NE Halsey, Suite 200 • Portland, OR 97232-1268 • (503) 288-1234 • Fax: (503) 288-2334

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

In reply refer to: PMT

SEP 26 1994

Amendatory Agreement No. 1
Contract No. DE-MS79-94BP94523

Mr. Joseph W. Nadal
Director of Power Management
Pacific Northwest Generating Cooperative
711 NE. Halsey, Suite 200
Portland, OR 97232

Dear Mr. Nadal:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and the Pacific Northwest Generating Cooperative (PNGC), an Oregon cooperative corporation, to amend Contract No. DE–MS79–94BP94523 (Capacity Ownership Agreement), executed by PNGC on September 23, 1994, and responds to PNGC's August 24, 1994, letter regarding the Capacity Ownership Agreement. This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and PNGC agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) PNGC may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PNGC. PNGC agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to PNGC under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) PNGC hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. PNGC does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of

Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to PNGC consistent with the above.

PNGC and Bonneville agree to negotiate in good faith the terms and conditions under which PNGC shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PNGC or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only PNGC)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to PNGC shall mean PNGC or its designee. Any such designee shall be identified in writing by PNGC to Bonneville. Only one entity may submit schedules on PNGC's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to PNGC, please sign and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Walter E. Pollock
Group Vice President, Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

PACIFIC NORTHWEST GENERATING COOPERATIVE

By _____

Name David E. Piper
(Print/Type)

Title Executive V.P. & General Manager

Date 9/30/94

Effective Date _____

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AUTHENTICATED COPY

Contract No. DE-MS79-94BP94523

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC NORTHWEST GENERATING COOPERATIVE

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (PNGC's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the PACIFIC NORTHWEST GENERATING COOPERATIVE (PNGC), an Oregon cooperative corporation. Each of Bonneville and PNGC is sometimes referred to individually in this Agreement as "Party"; Bonneville and PNGC are sometimes referred to together in this Agreement as "Parties."

W I T N E S S E T H :

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and PNGC executed a Memorandum of Understanding, DE-MS79-92BP93488, dated October 11, 1991, which, among other things, sets forth the principles for PNGC's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and PNGC are executing Contract No. DE-MS79-94BP94151 to provide PNGC with, among other things, network wheeling between the John Day Substation and PNGC's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and PNGC agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by PNGC's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than PNGC) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than PNGC) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PNGC pursuant to this Agreement, which percentage is determined by dividing PNGC's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of PNGC pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PNGC pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by PNGC's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with

the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by PNGC to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by PNGC.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PNGC for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PNGC for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by PNGC's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by PNGC pursuant to this Agreement, which percentage is determined by dividing PNGC's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of PNGC's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or PNGC.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the later of (1) the date of execution and delivery of this Agreement by both of the Parties, and (2) the date by which this Agreement has, with respect to PNGC, been approved by the Rural Electrification Administration (REA). To the extent required to do so by REA, PNGC shall submit this Agreement to REA for approval no later than three Working Days after the date on which this Agreement is executed by both Parties. Bonneville shall provide PNGC with a copy of the executed Agreement on the next Working Day after Bonneville executes the Agreement. PNGC shall use best efforts to obtain from REA on the earliest possible date REA's permission that this Agreement become effective in accordance with subsection 2(a). This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by PNGC until payment is made by PNGC pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from PNGC pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate

this Agreement by delivering to PNGC written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to PNGC pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to PNGC, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, PNGC purchases from Bonneville and Bonneville sells to PNGC the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, PNGC shall notify Bonneville in writing of PNGC's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and PNGC shall have the right to utilize its Scheduling Share pursuant to the paragraph PNGC elects. Prior to Bonneville's receipt of such notification, PNGC shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If PNGC fails to make an election within the

prescribed time period, PNGC shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), PNGC shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that PNGC does not own at the California-Oregon border or for which transmission PNGC receives any revenue that would be reportable in PNGC's accounting system where revenues received for wheeling for other entities would be booked.

(B) If PNGC's Scheduling Share is not fully utilized by PNGC in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of PNGC's Scheduling Share for such hour but no longer than such hour. PNGC shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), PNGC's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that PNGC has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of PNGC's Scheduling Share. In return for PNGC's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay PNGC

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-

south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of PNGC's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of PNGC's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When PNGC's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie

Operational Transfer Capability such that PNGC's Scheduling Share for such hour is less than the MW amount of the aggregate of PNGC's net firm transactions identified by PNGC to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of PNGC's firm transactions that equals the difference between PNGC's Scheduling Share for such hour and the MW amount of the aggregate of PNGC's firm transactions for such hour up to, but not in excess of, PNGC's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom PNGC is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. PNGC shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to PNGC pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for

Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to PNGC pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PNGC or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, PNGC shall identify such firm transaction to Bonneville. PNGC shall identify such firm transaction to Bonneville by providing to Bonneville a copy of PNGC's contract for such firm transaction (after information considered proprietary by PNGC has been redacted by PNGC). Bonneville shall review such contract to verify that the transaction is firm. If PNGC and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) PNGC retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) PNGC may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PNGC. PNGC shall have no obligation under this Agreement to make available to Bonneville any portion of PNGC's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over PNGC's Scheduling Share without PNGC's prior consent.

(B) PNGC hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide PNGC with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) PNGC shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when PNGC uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) PNGC (and only PNGC) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to PNGC's Scheduling Share for such hour. The MW amount of PNGC's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of PNGC's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) PNGC shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to PNGC on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify PNGC of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor

(Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify PNGC no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify PNGC no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) PNGC shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, PNGC shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) PNGC shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make PNGC's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that PNGC's schedule exceeds PNGC's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to PNGC information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify PNGC in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) PNGC's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) PNGC's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. PNGC may elect to acquire a share of such Upgrade in an amount up to PNGC's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, PNGC shall notify Bonneville in writing of PNGC's decision regarding such acquisition. If PNGC elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, PNGC's notice to Bonneville shall include the percentage of such Upgrade that PNGC elects to acquire (Acquisition Percentage). If PNGC fails to notify Bonneville within such 100-day period, PNGC shall be deemed to have elected not to acquire any of such Upgrade.

(d) If PNGC elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to PNGC shall be PNGC's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. PNGC shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If PNGC's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to PNGC and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If PNGC and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), PNGC may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to PNGC such portion of the Unacquired Share as has been apportioned to PNGC pursuant to the Apportionment, and Bonneville shall offer to PNGC such portion of the Unacquired Share.

(2) If Bonneville does not receive from PNGC and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to PNGC and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = PNGC's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following PNGC's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), PNGC shall notify Bonneville in writing of PNGC's decision regarding acquisition of the Additional Share Offered. If PNGC fails to notify Bonneville within such 30-day period, PNGC shall be deemed to have elected not to acquire any of the Additional Share Offered. If PNGC elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) PNGC shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as PNGC elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to PNGC with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by PNGC pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. PNGC shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After PNGC has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), PNGC's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from PNGC's elections pursuant to subsections 5(c) and (e). Revision

of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by PNGC to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by PNGC in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by PNGC to any other Capacity Owner of all or part of its Capacity Ownership Share and all of PNGC's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by PNGC of the entire Agreement and of all of PNGC's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by PNGC of this Agreement or of any of PNGC's rights under this Agreement as security for any indebtedness, whether present or future, of PNGC pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between PNGC and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if PNGC has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, PNGC shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If PNGC transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, PNGC shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance

outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to PNGC's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify PNGC in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify PNGC in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. PNGC's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and PNGC based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and PNGC have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to PNGC pursuant to this subsection 7(d) shall not be payable by PNGC pursuant to this Agreement.

(e) Bonneville shall provide PNGC notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on PNGC's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to PNGC's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain PNGC's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately

preceding clause (ii) that would have a substantial negative impact on PNGC's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without PNGC's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, PNGC hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, PNGC shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to PNGC in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to PNGC for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. PNGC shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and PNGC agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to PNGC, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, PNGC shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to PNGC, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of

Bonneville and PNGC agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by PNGC pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to PNGC pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to PNGC a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then PNGC shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to PNGC, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to

the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and PNGC agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from PNGC pursuant to paragraph 9(a)(1), Bonneville shall bill PNGC on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. PNGC shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing PNGC pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill PNGC on the monthly power bill, and PNGC shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being

hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to PNGC the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide PNGC written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to PNGC an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in

Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to PNGC on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PNGC shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to PNGC an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B,

D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to PNGC on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PNGC shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill PNGC pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to PNGC or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill PNGC on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. PNGC shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill PNGC the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to PNGC an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PNGC such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PNGC shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to PNGC an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PNGC such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PNGC shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill PNGC pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term

"AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill PNGC for wheeling provided pursuant to section 3(b)(1)(C)(i) on PNGC's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and PNGC shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, PNGC shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to PNGC's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to PNGC pursuant to section 4 without incurring any liability to PNGC therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by PNGC of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which PNGC makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, PNGC shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), PNGC shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by PNGC pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by PNGC pursuant to this Agreement; provided, however that PNGC's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect

to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to PNGC pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to PNGC pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to PNGC, in a lump sum, any refund due to PNGC pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to PNGC pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to PNGC under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to PNGC by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of PNGC, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by PNGC from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on PNGC's power bill.

10. **TRANSMISSION LOSSES**

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by PNGC pursuant to this Agreement, PNGC shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of PNGC and

Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to PNGC's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. PNGC's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of PNGC's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) PNGC's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify PNGC in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written

notice to PNGC of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to PNGC for purposes of effectuating remedial actions pursuant to this section.

(b) **PNGC's Responsibilities**

(1) PNGC shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain PNGC's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm PNGC's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, PNGC shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain PNGC's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by PNGC pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be

determined by dividing the amount of power scheduled by PNGC on PNGC's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) PNGC shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to PNGC's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) PNGC and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of PNGC pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

PNGC may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period PNGC fails to appoint a representative to the Committee, PNGC waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. PNGC hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Director of Power Management

Alternate:

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than PNGC, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to PNGC, and PNGC shall not have any obligation

pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection

13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among PNGC and Capacity Owners other than PNGC and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss

factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for

documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of PNGC's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into

good faith negotiations with PNGC and Capacity Owners other than PNGC regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of PNGC's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which PNGC is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, PNGC shall act through the Committee. Each of Bonneville and PNGC agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that

has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and PNGC, respectively.

The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and PNGC each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no

authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then PNGC shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill PNGC its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the PNGC or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of PNGC pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of PNGC's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6

and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by

either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity

Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or PNGC, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating

Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief

Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the

Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of

Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon PNGC and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to PNGC pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to PNGC pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge PNGC or any Capacity Owner other than PNGC for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PNGC a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to PNGC a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to PNGC as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PNGC's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to PNGC.

(f) If an audit report provided to Bonneville by PNGC pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PNGC a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to PNGC a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to PNGC as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PNGC's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to PNGC; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if

Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) PNGC shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If PNGC chooses not to participate in any audit undertaken by the Committee, then PNGC shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal

course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by PNGC of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If PNGC is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review PNGC's books, records, and documents that directly pertain to the revenue reportable in PNGC's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

PNGC shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless PNGC is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether PNGC has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to PNGC or by a seller of power or energy, which power or energy is not resource-specific and is delivered to PNGC at a point that connects one or more resources or transmission systems.

18. **ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION**

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, PNGC may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PNGC may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PNGC may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by

PNGC to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PNGC's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PNGC has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PNGC's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment,

Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of PNGC's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives PNGC' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives PNGC's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to PNGC of the amount of the Refunded Lump Sum Payment.

If PNGC elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to PNGC and Capacity Owners other than PNGC, or to any of them, the cost to Bonneville of the

Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PNGC or any Capacity Owner other than PNGC.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), PNGC may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PNGC may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PNGC may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PNGC's notification to terminate this Agreement pursuant to this subsection 18(c) except

for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PNGC has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PNGC's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + R = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the

first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to PNGC of the amount of Refunded Lump Sum Payment.

If PNGC elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to PNGC and Capacity Owners other than PNGC, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because

it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PNGC or any Capacity Owner other than PNGC.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, PNGC, and Capacity Owners other than PNGC shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place PNGC in substantially the same position with respect to PNGC's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, PNGC, and Capacity Owners other than PNGC shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, PNGC, and Capacity Owners other than PNGC reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, PNGC, and Capacity Owners other than PNGC do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of PNGC and Capacity Owners other than PNGC and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, PNGC, and Capacity Owners other than PNGC are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, PNGC may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to PNGC's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should PNGC elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) PNGC shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an

amount of power on the PNW-PSW Intertie up to PNGC's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to PNGC a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in PNGC's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of PNGC's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to PNGC pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by PNGC to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to PNGC of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) PNGC's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If PNGC fails to terminate the Agreement pursuant to subsection 18(e) as prescribed

therein as a result of FERC action, PNGC shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and PNGC shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, PNGC and Capacity Owners other than PNGC. If Bonneville and PNGC do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill PNGC, and PNGC shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time,

the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in PNGC's

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by PNGC and Capacity Owners other than PNGC.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and PNGC agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. **WAIVER**

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. **MISCELLANEOUS**

(a) **Effect of Section Headings**

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. PNGC shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or

any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to PNGC an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, PNGC during the development or consideration of any offer to any Capacity Owner other than PNGC to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that PNGC is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the PNGC's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by PNGC acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September 27, 1994

Date September 27, 1994

Pacific Northwest Generating Cooperative

By David E. Piper

Name DAVID E. PIPER
(Print/Type)

Title EXEC. VICE PRESIDENT

Date 9/26/94

/s/ DAVID E. PIPER

Executive Vice President

September 26, 1994

Effective Date _____

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$(XX))} * \%}{725\ \text{MW} * \#\ \text{months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	50 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual		(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	PNGC's Capacity Ownership Share	=	50 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$10,750,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to PNGC. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 7, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	PNGC's Capacity Ownership Share	=		50 MW
2.	Adjusted Capacity Ownership Price	X	$	
3.	Adjusted Lump Sum Payment[1]	=		
4.	Initial Lump Sum Payment	–		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to PNGC	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to PNGC	=		

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or PNGC receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	PNGC's Capacity Ownership Share	=		50 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to PNGC	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to PNGC	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or PNGC receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or PNGC receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or PNGC receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to PNGC's schedules for transactions transmitted on PNGC's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to PNGC's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	180 MVAR Reactor Bank No. 1	100	100
	• Breaker D#4222	100	100
	• Isolating Switch D#4060	100	100
	• Associated Arresters	100	100
	300 MVAR Reactor Bank No. 2	100	100
	• Breaker D#4720	100	100
	• Isolating Switch D#4719	100	100
	• Associated Arresters	100	100
	• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
	• Breaker D#4038	100	100
	• Isolating Switch D#4062	100	100
	• Neutral isolating switch D#4109/4081	100	100
	• Associated Arresters	100	100
	• Associated PTs	100	100
	• North Main Bus 500 kV PTs	100	100
	• South Main Bus 500 kV PTs	100	100
	Station General		
9.	**Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
	Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
10.	**Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
11.	**Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

PNGC, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation; liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, PNGC and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, PNGC and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by PNGC or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of PNGC or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, PNGC and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If , during any 12-month period (including the 12 months preceding the award of this contract), PNGC has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, PNGC shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, PNGC shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, PNGC agrees as follows:

(1) PNGC shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) PNGC shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) PNGC shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) PNGC shall, in all solicitations or advertisements for employees placed by or on behalf of PNGC, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) PNGC shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of PNGC's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) PNGC shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) PNGC shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) PNGC shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain PNGC's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that PNGC is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and PNGC may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against PNGC as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) PNGC shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) PNGC shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if PNGC becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, PNGC may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) PNGC certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. PNGC agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) PNGC agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by PNGC to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) PNGC hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. PNGC further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of PNGC's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

PNGC shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) PNGC acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) PNGC agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) PNGC agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event PNGC and Bonneville shall, in concert with the Capacity Owners other than PNGC, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by PNGC pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that PNGC shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1			
B. Other PNW AC Intertie costs	2			
C. Total Other Costs	3			

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1			
Total contracts and rates cost from rate case	2			
Contracts and rates cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5			
Contracts and rates indirect costs	6			
Contracts and rates overhead costs	7			
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8			
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9			

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		_____	
Total power scheduling cost from rate case	2		_____	
Power scheduling cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Power Scheduling Costs				
Power scheduling direct costs	5	_____	_____	_____
Power scheduling indirect costs	6	_____	_____	_____
Power scheduling overhead costs	7	_____	_____	_____
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2			
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	( )	( )	( )
D. End of Term Costs	4			

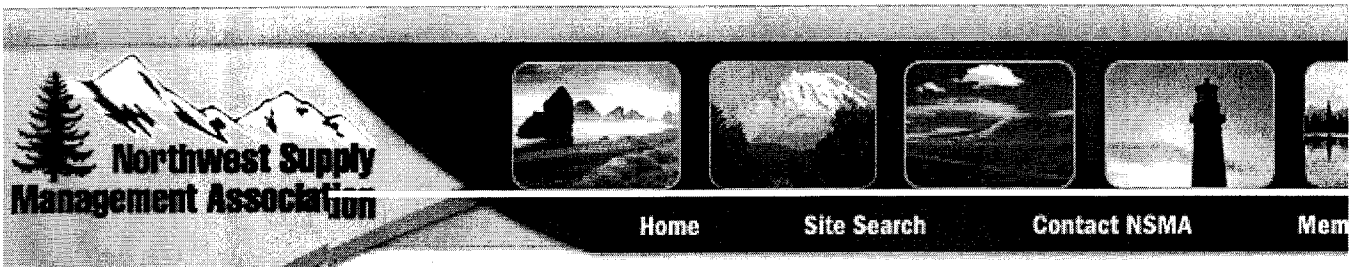
PNGC's Initial Transaction with California Utility

Name of parties: PNGC / Turlock Irrigation District

Term of Contract: December 31, 2018

Date of Execution: November 10, 1992

Amount of Transaction (MW): 52 MW



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BONNEVILLE
POWER ADMINISTRATION

Transmission Business Line (TBL)

Draft Business Practice LOS-001.3

Real Power Loss Return Methodology, Version 3

Effective: March 1, 2004
Posted: February 24, 2004

Revised as follows:

- *Changed the frequency that customers are permitted to change Real Power Loss Providers from twice a year to four times a year in response to customer input.*
- *Other minor revisions for clarity and consistency.*

This document defines the process and guidelines by which transmission customers must return Real Power Losses to the Bonneville Power Administration (BPA) Power Business Line (PBL). The BPA Transmission Business Line (TBL) will refuse all schedule requests for Transmission Customers that have not made a declaration of their Real Power Loss Provider.

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B. Real Power Loss Methodology for Point-to-Point (PTP) Customers 1

C. Real Power Loss Returns for non-Point-to-Point Customers 3

Revision History 3

A. Customers That Are Not Required to Return Real Power Losses

All Transmission Customers must return Real Power Losses, with the following exceptions:

- **BPA PBL Full Requirements Customers** do not need to return losses for energy delivered under a subscription contract that includes losses.
- **BPA PBL Partial Requirements Customers** do not need to return losses for energy delivered under BPA PBL Partial Requirements subscription agreements. *However*, Partial Requirements Customers must return Real Power Losses for the non-Federal portion of their power deliveries, and must notify TBL of their Real Power Loss provider for the non-Federal portion of their power deliveries.
- BPA PBL **Block** power customers are not required to return losses for energy delivered under a BPA PBL Block power contract.

B. Real Power Loss Methodology for Point-to-Point (PTP) Customers

1. Real Power Loss returns can be from a Control Area, a system, or a remote generator resource within the network segment. If a remote resource is down for any reason, the Transmission Customer must deliver energy to the remote

resource to ensure that the loss schedule is returned. This provides comparable loss return schedules for all providers of loss schedules from one loss provider. All losses must be provided from one Control Area, one system, or one remote generator.

2. The Transmission Customer is responsible for delivering its required Real Power Losses to TBL. A customer may elect to be its own Real Power Loss Provider, or may designate one alternate Real Power Loss Provider to deliver the Transmission Customer's Real Power Losses to TBL. TBL will not charge Transmission Customers for transmission to return Real Power Losses. A Transmission Customer's alternate Real Power Loss Provider may use its own transmission or the Transmission Customer's "no charge" transmission reservation, as described in section 3, to return the Transmission Customer's losses to TBL on behalf of the Transmission Customer.

   Transmission Customers must notify their TBL Account Executive in writing of their designated Real Power Loss Provider using the form provided by the designated account executive. Transmission Customers may change their Real Power Loss provider with 60 days' prior written notice to their TBL Account Executive. Transmission Customers may not change their Real Power Loss Provider more than four times in any fiscal year (i.e., customers are allowed no more than 4 RPL Providers in a fiscal year). Changes of Real Power Loss Providers may occur only at the beginning of a month.

3. Transmission charges associated with the return of Real Power Losses are already included in the charges associated with the transmission service that generated the losses, so TBL does not assess additional transmission charges for the return of Real Power Losses. However, to allow TBL to determine and track Available Transmission Capacity (ATC), Transmission Customers or their alternate Real Power Loss Provider must return Real Power Losses to PBL on firm transmission using either "no charge reservations for losses" or previously reserved transmission.

   A reservation product code for "no charge reservation for losses" is posted on the NW Open Access Same Time Information System (OASIS). The transmission loss reservation must show the Point Of Receipt (POR) as the Real Power Loss provider and the Point Of Delivery (POD) will be BPA Power.

   For TBL posted external constrained paths, Transmission Customers or their alternate Real Power Loss Providers for transmission may use previously reserved transmission at a POR or may request a new "no charge reservation for losses". "No charge reservation for losses" can be used only for transmission of loss schedules.

   Real Power Loss return schedules are firm and subject to pro rata curtailment in real time. Real Power Loss returns that are curtailed must be returned as soon as possible and no later than 168 hours from the time of the curtailment.

4. TBL will continue to calculate Real Power Losses for its transmission system, and will send a daily report to all Transmission Customers with their loss schedules. Those schedules may also be viewed on the Customer Web Interface (CWI). Please contact TBL Scheduling for more information on how to get access to CWI.

5. The Unauthorized Increase Charge (UIC), Section II. G. of TBL's 2004 Transmission and Ancillary Service Rate Schedules, will apply if the Transmission Customer, using its own Reserved Capacity to return Real Power Losses in lieu of a "no charge reservation for losses," schedules transmission in excess of its Reserved Capacity.

C. Real Power Loss Returns for non-Point-to-Point Customers

Non-PTP Transmission Customers will be charged as follows:

- Network Integration (NT) Transmission Customers will not be charged transmission for loss schedules. A Real Power Loss provider must be identified and losses returned, except as provided in Section A.
- Slice Customers do not require a "no charge reservation" when Slice is being used to provide the return of the Slice Customer's Real Power Losses. These losses are calculated in the same way as losses for other customers. However, instead of a return schedule the losses are deducted from the customer's share of Slice 168 hours later, prior to the share being made available for scheduling.
- Formula Power Transmission (FPT) Customer losses are as described in the Customer's FPT Contracts.
- Integration of Resources (IR) Customer losses are as described in the Customer's IR Contract.

If you have questions or comments regarding this posting, please contact Shirley Buckmier at smbuckmier@bpa.gov or your TBL Customer Account Executive.

Revision History

Version/Date	Summary
06/26/2003	• Section C revised to clarify how Real Power Losses are handled for Slice customers. • Added section A. to clarify which customers are not required to return real power losses. This was previously posted in a linked document and the link does not work consistently. • Removed nonworking link. • Renumbered/reformatted sections to conform to conventions. • Removed all references to submitting notification on OASIS, this capability does not exist. • Removed requirement for yearly notification, this is no longer required. • Minor edits for clarity and correction of typographical errors. • Moved statement about refusal of schedule requests to the top of the document. • Revised language for clarity.
11/26/2001	Multiple marked updates.
09/20/2001	Minor revisions.

09/07/2001	Minor revisions.
09/06/2001	Added a link to a supplementary document
08/08/2001	Original business practice to define method for returning real power losses.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

JAN 11 1995

Amendatory Agreement No. 2
Contract No. DE-MS79-95BP94628

Mr. Jerry Miller, Manager
Power System Services
PacifiCorp
825 NE. Multnomah Street, Suite 625
Portland, OR 97232

Dear Mr. Miller:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and PacifiCorp, a corporation organized and existing under the laws of the State of Oregon, to amend Contract No. DE-MS79-95BP94628 (Capacity Ownership Agreement).

Bonneville and PacifiCorp agree that the first sentence of section 2(a) shall be stricken and replaced with the following sentence:

> "This Agreement shall become effective January 1, 1995, unless otherwise determined by FERC."

Should the Federal Energy Regulation Committee determine the Effective Date of the Capacity Ownership Agreements to be after January 1, 1995, PacifiCorp agrees to pay Bonneville Southern Intertie firm wheeling charges for PacifiCorp's use of its Capacity Ownership Share between January 1, 1995, and the Effective Date as established by FERC.

If the foregoing terms are acceptable to PacifiCorp, please sign both copies and return one copy of this amendment. The remaining copy is for your files.

Sincerely,

Senior Account Executive

Name Patrick G. McRae
(Print/Type)

ACCEPTED:

PACIFICORP

By

Name Jerry D. Miller
(Print/Type)

Title Manager, Power System Services

Date January 23, 1995

(PMLAN-MPSM-W:\MPSM\CTL\TRAGT\94628.DOC)

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Amendatory Agreement No. 1
Contract No. DE-MS79-95BP94628

Mr. Jerry Miller, Director
Power System Services
PacifiCorp Electric Operations
825 NE. Multnomah Street, Suite 625
Portland, OR 97232

Dear Mr. Miller:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and PacifiCorp Electric Operations (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon, to amend Contract No. DE–MS79–95BP94628 (Capacity Ownership Agreement). This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and PacifiCorp agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) PacifiCorp may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PacifiCorp. PacifiCorp agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to PacifiCorp under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) PacifiCorp hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. PacifiCorp does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of

Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to PacifiCorp consistent with the above.

PacifiCorp and Bonneville agree to negotiate in good faith the terms and conditions under which PacifiCorp shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PacifiCorp or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only PacifiCorp)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to PacifiCorp shall mean PacifiCorp or its designee. Any such designee shall be identified in writing by PacifiCorp to Bonneville. Only one entity may submit schedules on PacifiCorp's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to PacifiCorp, please sign both copies and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Senior Account Executive

Name Patrick G. McRae
(Print/Type)

ACCEPTED:

PACIFICORP/ELECTRIC OPERATIONS

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date December 27, 1994

(PMLAN-MPSM-W:\MPSM\CT\LTRAGT\94628AA1.DOC)

Contract No. DE-MS79-95BP94628

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (PacifiCorp's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of December 28, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the PACIFICORP (PacifiCorp), a corporation operating and existing under the laws of the state of Oregon. Each of Bonneville and PacifiCorp is sometimes referred to individually in this Agreement as "Party"; Bonneville and PacifiCorp are sometimes referred to together in this Agreement as "Parties."

W I T N E S S E T H :

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by PacifiCorp's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and PacifiCorp executed a Memorandum of Understanding, DE-MS79-91BP93469, dated September 18, 1991, which, among other things, sets forth the principles for PacifiCorp's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and PacifiCorp agree as follows:

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by Capacity Owners and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PacifiCorp pursuant to this Agreement, which percentage is determined by dividing PacifiCorp's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of PacifiCorp pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PacifiCorp pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year

Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by PacifiCorp's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for

such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or

Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice)

resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Oregon, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by PacifiCorp to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each

Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by PacifiCorp.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PacifiCorp for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PacifiCorp for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by PacifiCorp's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement, interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by PacifiCorp pursuant to this Agreement, which percentage is determined by dividing

PacifiCorp's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of PacifiCorp's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or PacifiCorp.

2. TERM AND TERMINATION

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by PacifiCorp until payment is made by PacifiCorp pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from PacifiCorp pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to PacifiCorp written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to PacifiCorp pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes

and delivers this Agreement to PacifiCorp, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, PacifiCorp purchases from Bonneville and Bonneville sells to PacifiCorp the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, PacifiCorp shall notify Bonneville in writing of PacifiCorp's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and PacifiCorp shall have the right to utilize its Scheduling Share pursuant to the paragraph PacifiCorp elects. Prior to Bonneville's receipt of such notification, PacifiCorp shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If PacifiCorp fails to make an election within the prescribed time period, PacifiCorp shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) No Third Party Wheeling

(A) Except as expressly provided in subparagraph 3(b)(1)(B), PacifiCorp shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that PacifiCorp does not own at the California-Oregon border or for which transmission PacifiCorp receives any revenue that would be reportable in PacifiCorp's accounting system where revenues received for wheeling for other entities would be booked.

(B) If PacifiCorp's Scheduling Share is not fully utilized by PacifiCorp in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of PacifiCorp's Scheduling Share for such hour but no longer than such hour. PacifiCorp shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), PacifiCorp's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that PacifiCorp has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of PacifiCorp's Scheduling Share. In return for PacifiCorp's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay PacifiCorp

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of PacifiCorp's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of PacifiCorp's unused

Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When PacifiCorp's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that PacifiCorp's Scheduling Share for such hour is less than the MW amount of the aggregate of PacifiCorp's net firm transactions identified by PacifiCorp to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of PacifiCorp's firm transactions that equals the difference between PacifiCorp's Scheduling Share for such hour and the MW amount of the aggregate of PacifiCorp's firm transactions for such hour up to, but not in

excess of, PacifiCorp's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom PacifiCorp is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. PacifiCorp shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to PacifiCorp pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to PacifiCorp pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PacifiCorp or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, PacifiCorp shall identify such firm transaction to

Bonneville. PacifiCorp shall identify such firm transaction to Bonneville by providing to Bonneville a copy of PacifiCorp's contract for such firm transaction (after information considered proprietary by PacifiCorp has been redacted by PacifiCorp). Bonneville shall review such contract to verify that the transaction is firm. If PacifiCorp and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) PacifiCorp retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) PacifiCorp may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PacifiCorp. PacifiCorp shall have no obligation under this Agreement to make available to Bonneville any portion of PacifiCorp's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over PacifiCorp's Scheduling Share without PacifiCorp's prior consent.

(B) PacifiCorp hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term

Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide PacifiCorp with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) PacifiCorp shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when PacifiCorp uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) PacifiCorp (and only PacifiCorp) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to PacifiCorp's Scheduling Share for such hour. The MW amount of PacifiCorp's Scheduling Share deemed to be scheduled on the PNW AC Intertie

pursuant to this Agreement, in any hour, shall be determined as the net of PacifiCorp's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) PacifiCorp shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to PacifiCorp on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify PacifiCorp of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify PacifiCorp no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify PacifiCorp no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) PacifiCorp shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, PacifiCorp shall submit its

Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) PacifiCorp shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the

hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make PacifiCorp's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that PacifiCorp's schedule exceeds PacifiCorp's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to PacifiCorp information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify PacifiCorp in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) PacifiCorp's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) PacifiCorp's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such

Upgrade. PacifiCorp may elect to acquire a share of such Upgrade in an amount up to PacifiCorp's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, PacifiCorp shall notify Bonneville in writing of PacifiCorp's decision regarding such acquisition. If PacifiCorp elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, PacifiCorp's notice to Bonneville shall include the percentage of such Upgrade that PacifiCorp elects to acquire (Acquisition Percentage). If PacifiCorp fails to notify Bonneville within such 100-day period, PacifiCorp shall be deemed to have elected not to acquire any of such Upgrade.

(d) If PacifiCorp elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to PacifiCorp shall be PacifiCorp's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. PacifiCorp shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If PacifiCorp's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to PacifiCorp and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If PacifiCorp and each of such other Capacity Owners have agreed in writing to an apportionment

as among themselves of the Unacquired Share (Apportionment), PacifiCorp may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to PacifiCorp such portion of the Unacquired Share as has been apportioned to PacifiCorp pursuant to the Apportionment, and Bonneville shall offer to PacifiCorp such portion of the Unacquired Share.

(2) If Bonneville does not receive from PacifiCorp and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to PacifiCorp and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = PacifiCorp's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following PacifiCorp's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), PacifiCorp shall notify Bonneville in writing of PacifiCorp's decision regarding acquisition of the Additional Share Offered. If PacifiCorp fails to notify Bonneville within such 30-day period, PacifiCorp shall be deemed to have elected not to acquire any of the Additional Share Offered. If PacifiCorp elects pursuant to this paragraph

5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) PacifiCorp shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as PacifiCorp elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to PacifiCorp with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by PacifiCorp pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. PacifiCorp shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After PacifiCorp has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), PacifiCorp's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from PacifiCorp's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by PacifiCorp to any person without

Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by PacifiCorp in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by PacifiCorp to any other Capacity Owner of all or part of its Capacity Ownership Share and all of PacifiCorp's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by PacifiCorp of the entire Agreement and of all of PacifiCorp's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by PacifiCorp of this Agreement or of any of PacifiCorp's rights under this Agreement as security for any indebtedness, whether present or future, of PacifiCorp pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between PacifiCorp and any mortgagee,

trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if PacifiCorp has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, PacifiCorp shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If PacifiCorp transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, PacifiCorp shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to PacifiCorp's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville

shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify PacifiCorp in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify PacifiCorp in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. PacifiCorp's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and PacifiCorp based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately

succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and PacifiCorp have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to PacifiCorp pursuant to this subsection 7(d) shall not be payable by PacifiCorp pursuant to this Agreement.

(e) Bonneville shall provide PacifiCorp notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on PacifiCorp's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to PacifiCorp's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain PacifiCorp's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on PacifiCorp's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without PacifiCorp's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, PacifiCorp hereby consents to Bonneville's modification of the Northwest Intertie Agreements or

Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, PacifiCorp shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to PacifiCorp in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to PacifiCorp for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. PacifiCorp shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and PacifiCorp agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) Calculation and Billing of the Adjusted Capacity Ownership Price

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual

construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to PacifiCorp, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, PacifiCorp shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to PacifiCorp, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and PacifiCorp agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by PacifiCorp pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to PacifiCorp pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to PacifiCorp a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership

Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then PacifiCorp shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to PacifiCorp, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and PacifiCorp

agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from PacifiCorp pursuant to paragraph 9(a)(1), Bonneville shall bill PacifiCorp on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. PacifiCorp shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing PacifiCorp pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill PacifiCorp on the monthly power bill, and PacifiCorp shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual

Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to PacifiCorp the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide PacifiCorp written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to PacifiCorp an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and

forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to PacifiCorp on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PacifiCorp shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to PacifiCorp an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast

Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to PacifiCorp on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PacifiCorp shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill PacifiCorp pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and

until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to PacifiCorp or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill PacifiCorp on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. PacifiCorp shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual

Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill PacifiCorp the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to PacifiCorp an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PacifiCorp such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PacifiCorp shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to PacifiCorp an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual

Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PacifiCorp such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PacifiCorp shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill PacifiCorp pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill PacifiCorp for wheeling provided pursuant to section 3(b)(1)(C)(i) on PacifiCorp's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and PacifiCorp shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, PacifiCorp shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to PacifiCorp's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or

9(d), Bonneville shall be entitled to suspend performance of its obligations to PacifiCorp pursuant to section 4 without incurring any liability to PacifiCorp therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by PacifiCorp of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which PacifiCorp makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, PacifiCorp shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), PacifiCorp shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by PacifiCorp pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by PacifiCorp pursuant to this Agreement; provided, however that PacifiCorp's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to PacifiCorp pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to PacifiCorp pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to PacifiCorp, in a lump sum, any refund due to PacifiCorp pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to PacifiCorp pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to PacifiCorp under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to PacifiCorp by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of PacifiCorp, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by PacifiCorp from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on PacifiCorp's power bill.

10. **TRANSMISSION LOSSES**

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by PacifiCorp pursuant to this Agreement, PacifiCorp shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of PacifiCorp and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to PacifiCorp's net PNW AC Intertie schedule multiplied

by the appropriate loss factor specified in Exhibit E. PacifiCorp's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of PacifiCorp's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) PacifiCorp's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify PacifiCorp in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to PacifiCorp of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having

available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to PacifiCorp for purposes of effectuating remedial actions pursuant to this section.

(b) **PacifiCorp's Responsibilities**

(1) PacifiCorp shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain PacifiCorp's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm PacifiCorp's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, PacifiCorp shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain PacifiCorp's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by PacifiCorp pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by PacifiCorp on PacifiCorp's Scheduling Share in

such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) PacifiCorp shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to PacifiCorp's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) PacifiCorp and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of PacifiCorp pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

PacifiCorp may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period PacifiCorp fails to appoint a representative to the Committee, PacifiCorp waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. PacifiCorp hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Senior Vice President, Wholesale Transactions and Transmission

Alternate: Manager, Power System Services

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

If to PacifiCorp:

Senior Vice President, Wholesale Transactions
and Transmission
PacifiCorp Electric Operations
825 NE. Multnomah Street, Suite 625
Portland, OR 97232
Telephone (503) 731-2157
Facsimile (503) 731-2136

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than PacifiCorp, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to PacifiCorp, and PacifiCorp shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a

planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among PacifiCorp and Capacity Owners other than PacifiCorp and Bonneville's *rationale for such apportionment;*

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the

costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) *such documentation, data, and information relating to* Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such

request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional

documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting

documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan

(either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of PacifiCorp's

rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 *total overhead power scheduling costs;*

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with PacifiCorp and Capacity Owners other than PacifiCorp regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan

is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of PacifiCorp's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which PacifiCorp is obligated to pay pursuant to the terms and conditions of this

Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, PacifiCorp shall act through the Committee. Each of Bonneville and PacifiCorp agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and PacifiCorp, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and PacifiCorp each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in

California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then PacifiCorp shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill PacifiCorp its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration

proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be

arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the PacifiCorp or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of PacifiCorp pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of PacifiCorp's rights and benefits pursuant to section 16(f), no

Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration

pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or PacifiCorp, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the

Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then

within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or

information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the

Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon PacifiCorp and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. **AUDIT RIGHTS**

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to PacifiCorp pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to PacifiCorp pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge PacifiCorp or any Capacity Owner other than PacifiCorp for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits

undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PacifiCorp a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to PacifiCorp a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to PacifiCorp as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PacifiCorp's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to PacifiCorp.

(f) If an audit report provided to Bonneville by PacifiCorp pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PacifiCorp a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to PacifiCorp a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to PacifiCorp as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PacifiCorp's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to PacifiCorp; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) PacifiCorp shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If PacifiCorp chooses not to participate in any audit undertaken by the Committee, then PacifiCorp shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and

Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by PacifiCorp of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If PacifiCorp is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review PacifiCorp's books, records, and documents that directly pertain to the revenue reportable in PacifiCorp's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

PacifiCorp shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless PacifiCorp is required by regulatory authority to purchase

or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether PacifiCorp has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to PacifiCorp or by a seller of power or energy, which power or energy is not resource-specific and is delivered to PacifiCorp at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, PacifiCorp may, within 90

days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PacifiCorp may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PacifiCorp may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PacifiCorp's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PacifiCorp has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PacifiCorp's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of PacifiCorp's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives PacifiCorp' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives PacifiCorp's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to PacifiCorp of the amount of the Refunded Lump Sum Payment.

If PacifiCorp elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to PacifiCorp and Capacity Owners other than PacifiCorp, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PacifiCorp or any Capacity Owner other than PacifiCorp.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), PacifiCorp may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PacifiCorp may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PacifiCorp may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PacifiCorp's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PacifiCorp has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PacifiCorp's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to PacifiCorp of the amount of Refunded Lump Sum Payment.

If PacifiCorp elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to PacifiCorp and Capacity Owners other than PacifiCorp, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PacifiCorp or any Capacity Owner other than PacifiCorp.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place PacifiCorp in substantially the same position with respect to PacifiCorp's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the

expiration of the AC-93 rate. Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of PacifiCorp and Capacity Owners other than PacifiCorp and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, PacifiCorp may elect, within 6 months of any of the foregoing events, to terminate this Agreement

and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to PacifiCorp's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should PacifiCorp elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) PacifiCorp shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to PacifiCorp's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to PacifiCorp a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in PacifiCorp's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of PacifiCorp's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to PacifiCorp pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by PacifiCorp to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each

monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to PacifiCorp of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) PacifiCorp's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If PacifiCorp fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, PacifiCorp shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period,

Bonneville and PacifiCorp shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, PacifiCorp and Capacity Owners other than PacifiCorp. If Bonneville and PacifiCorp do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill PacifiCorp, and PacifiCorp shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in PacifiCorp's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and

section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by PacifiCorp and Capacity Owners other than PacifiCorp.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and PacifiCorp agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be

applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. **NOTICES**

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

To PacifiCorp:

Senior Vice President, Wholesale Transactions
and Transmission
PacifiCorp Electric Operations
825 NE. Multnomah Street, Suite 625
Portland, OR 97232

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) Amendments

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) Entire Agreement

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. PacifiCorp shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to PacifiCorp an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, PacifiCorp during the development or consideration of any offer to any Capacity Owner other than

PacifiCorp to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate

set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that PacifiCorp is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the PacifiCorp's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by PacifiCorp acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any

right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Account Executive

Name Patrick G. McRae
(Print/Type)

Date December 28, 1994

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date December 27, 1994

Effective Date January 1, 1995

(PMLAN-MPB-W:\PMT\CT\94628.DOC)

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

(PMLAN-MPSD-W:\PMT\CT\94628EXA.DOC)

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in \$/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$(KK))} * \%}{\text{725 MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A. the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B. the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. *End of Term*

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	32 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

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Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual	(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1. Alvey (Marion-Alvey Caps)	$5,739		
2. Slatt (Loop in - Breaker)	3,044		
3. Grizzly (BPA Breakers)	11,044		
4. *Loop into Slatt*	656		
5. Malin-Meridian loop into Captain Jack	982		
6. Alvey Substation - BPA	8,168		
7. Dixonville - PacifiCorp	8,635		
8. Meridian - PacifiCorp	6,548		
9. Power System Control	3,575		
10. Alvey-Spencer - BPA	1,346		
11. Spencer-Dixonville - PacifiCorp	20,388		
12. Dixonville-Meridian - PacifiCorp	32,140		
SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent			
13. Captain Jack (BPA Breakers)	$14,335		
14. Captain Jack (Communication and Control)	5,100		
15. Captain Jack (Series Capacitors)	722		
16. Power System Control	5,596		
17. Captain Jack line to Oregon-Calif. border	5,724		
SUBTOTAL	$31,477		
50 PERCENT OF SUBTOTAL	15,739		
TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	PacifiCorp's Capacity Ownership Share	=	32 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$6,880,000
4.	Deduction: Negotiation Deposit with Interest		
5.	Due to Bonneville:	=	$6,880,000

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

D. ADJUSTED LUMP SUM PAYMENT

1.	PacifiCorp's Capacity Ownership Share	=	32 MW
2.	*Adjusted Capacity Ownership Price*	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	_____
5.	SUBTOTAL due to Bonneville, or Refund *Due to PacifiCorp*	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to PacifiCorp	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or PacifiCorp receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	PacifiCorp's Capacity Ownership Share	=		32 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	*Adjusted Lump Sum Payment/immediately* preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to PacifiCorp	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to PacifiCorp	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or PacifiCorp receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or PacifiCorp receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or PacifiCorp receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to PacifiCorp's schedules for transactions transmitted on PacifiCorp's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to PacifiCorp's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

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Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	McNary line terminal		
	• 500 kV MOD D#5023/7847	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
2.	**John Day 500 kV** (Dispatch one-line diagram No. 132281)		
	Grizzly No.2 line terminal		
	• Breaker D#4131	100	50
	• Breaker D#4134	100	100
	• MOD D#4132	100	50
	• MOD D#4133/7867	100	100
	• MOD D#4135	100	100
	• Associated Line PTs	100	100
	Grizzly No.1 line terminal		
	• Breaker D#4140	100	50
	• Breaker D#4143	100	100
	• MOD D#4141	100	50
	• MOD D#4142/7869	100	100
	• MOD D#4144	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
3.	**Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
	Slatt No. 1 line terminal		
	• Breaker D#4967	100	57
	• Isolating switch D#4966/7328	100	57
	• Isolating switch D#4968/7355	100	57
	• Ground switch D#7415	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Summer Lake No. 1 line terminal		
	• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (*PacifiCorp's one-line diagram* PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230.kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1
PacifiCorp	DE-MS79-95BP94628	32	0.9

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities
PacifiCorp: PacifiCorp Electric Operations

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Seattle, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Seattle and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Seattle and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Seattle or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Seattle or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Seattle and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Seattle has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Seattle shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Seattle shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Seattle agrees as follows:

(1) Seattle shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Seattle shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Seattle shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Seattle shall, in all solicitations or advertisements for employees placed by or on behalf of Seattle, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Seattle shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Seattle's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Seattle shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Seattle shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Seattle shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Seattle's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Seattle is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Seattle may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Seattle as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Seattle shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Seattle shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Seattle becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Seattle may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Seattle certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Seattle agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Seattle agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Seattle to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Seattle hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Seattle further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Seattle's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Seattle shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Seattle acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Seattle agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Seattle agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event PacifiCorp and Bonneville shall, in concert with the Capacity Owners other than PacifiCorp, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by PacifiCorp pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that PacifiCorp shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor [Line 1/Line 2]	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor [Line 4/Line 5]	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost [Line 3 * Line 6 * Line 7]	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost [Line 3 * Line 6 * Line 9]	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost [Line 3 * Line 6 * Line 11]	12	_____	_____	_____
F. Operations Cost [Lines 8 + 10 + 12]	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor [Line 1/Line 2]	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor [Schedule A, line 3]	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie [Line 4 * Line 3 * Line 5]	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost [Line 6 + Line 7]	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance *indirect cost*	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs [Lines 1 + 2 + 3 + 4]	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission [Line 1 + Line 2 - Line 3 - Line 4 - Line 5]	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie [Line 7/Line 8]	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost [Line 9 * Line 10]	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor [Line 1/Line 2]	3		_____	
B. Allocation Factor				
MFU allocation factor [Schedule A, line 3]	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs [Line 5 + Line 6 + Line 7]	8	_____	_____	_____
D. Contracts and Rates Cost [Line 8 * Line 3 * Line 4]	9	_____	_____	_____

hedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		_____	
Total power scheduling cost from rate case	2		_____	
Power scheduling cost functionalization factor [Line 1/Line 2]	3		_____	
B. Allocation Factor				
MFU allocation factor [Schedule A, line 3]	4		_____	
C. Total Power Scheduling Costs				

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2			
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	( )	( )	( )
D. End of Term Costs	4			

PacifiCorp's Initial Transaction with California Utility

Name of parties:

Term of Contract:

Date of Execution:

Amount of Transaction (MW):

(PMLAN-MPSD-W:\PMT\CT94628EXJ.DOC)

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

SEP 26 1994

In reply refer to: PMT

Amendatory Agreement No. 1
Contract No. DE-MS79-94BP94524

Mr. Steven J. Klein
Light Division Superintendent
City of Tacoma, Department of Public Utilities
3628 South 35th Street
Tacoma, WA 98411

Dear Mr. Klein:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and the City of Tacoma, Department of Public Utilities (Tacoma), a municipal corporation operating and existing under the laws of the State of Washington, to amend Contract No. DE–MS79–94BP94524 (Capacity Ownership Agreement), executed by Tacoma on September 23, 1994. This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and Tacoma agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) Tacoma may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Tacoma. Tacoma agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to Tacoma under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) Tacoma hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. Tacoma does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or

amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to Tacoma consistent with the above.

Tacoma and Bonneville agree to negotiate in good faith the terms and conditions under which Tacoma shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Tacoma or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only Tacoma)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to Tacoma shall mean Tacoma or its designee. Any such designee shall be identified in writing by Tacoma to Bonneville. Only one entity may submit schedules on Tacoma's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to Tacoma, please sign and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Walter E. Pollock
Group Vice President, Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

CITY OF TACOMA, DEPARTMENT OF PUBLIC UTILITIES

By _____

Name Steven J. Klein
(Print/Type)

Title Deputy Director/Light Superintendent

Date 10/27/94

Effective Date September 27, 1994

(PMLAN-W:\PMT\CONTRACT\LTR_AGMT\94524AM1.DOC)

Approved as to form & legality

_____
Chief Asst. City Attorney

AUTHENTICATED COPY Contract No. DE-MS79-94BP94524

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

CITY OF TACOMA, DEPARTMENT OF PUBLIC UTILITIES

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Tacoma's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the CITY OF TACOMA, DEPARTMENT OF PUBLIC UTILITIES (Tacoma), a municipal corporation operating and existing under the laws of the state of Washington. Each of Bonneville and Tacoma is sometimes referred to individually in this Agreement as "Party"; Bonneville and Tacoma are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Tacoma executed a Memorandum of Understanding, DE-MS79-91BP93468, dated September 23, 1991, which, among other things, sets forth the principles for Tacoma's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Tacoma are executing Contract No. DE-MS79-94BP93936 to provide Tacoma with, among other things, network wheeling between the John Day Substation and Tacoma's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Tacoma agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Tacoma's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Tacoma) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Tacoma) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Tacoma pursuant to this Agreement, which percentage is determined by dividing Tacoma's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Tacoma pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Tacoma pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Tacoma's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as

amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Tacoma to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Tacoma.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Tacoma for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Tacoma for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Tacoma's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Tacoma pursuant to this Agreement, which percentage is determined by dividing Tacoma's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Tacoma's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Tacoma.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Tacoma until payment is made by Tacoma pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Tacoma pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Tacoma written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Tacoma pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H,

and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Tacoma, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Tacoma purchases from Bonneville and Bonneville sells to Tacoma the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, Tacoma shall notify Bonneville in writing of Tacoma's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Tacoma shall have the right to utilize its Scheduling Share pursuant to the paragraph Tacoma elects. Prior to Bonneville's receipt of such notification, Tacoma shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Tacoma fails to make an election within the prescribed time period, Tacoma shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) No Third Party Wheeling

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Tacoma shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Tacoma does not own at the California-Oregon border or for which transmission Tacoma receives any revenue that would be reportable in

Tacoma's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Tacoma's Scheduling Share is not fully utilized by Tacoma in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Tacoma's Scheduling Share for such hour but no longer than such hour. Tacoma shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Tacoma's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Tacoma has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Tacoma's Scheduling Share. In return for Tacoma's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Tacoma

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Tacoma's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-

north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Tacoma's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Tacoma's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Tacoma's Scheduling Share for such hour is less than the MW amount of the aggregate of Tacoma's net firm transactions identified by Tacoma to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Tacoma's firm transactions that equals the difference between Tacoma's Scheduling Share for such hour and

the MW amount of the aggregate of Tacoma's firm transactions for such hour up to, but not in excess of, Tacoma's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Tacoma is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Tacoma shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Tacoma pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Tacoma pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Tacoma or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Tacoma shall identify such firm transaction to Bonneville. Tacoma shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Tacoma's contract for such firm transaction (after information considered proprietary by Tacoma has been redacted by Tacoma). Bonneville shall review such contract to verify that the transaction is firm. If Tacoma and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Tacoma retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Tacoma may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Tacoma. Tacoma shall have no obligation under this Agreement to make available to Bonneville any portion of Tacoma's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Tacoma's Scheduling Share without Tacoma's prior consent.

(B) Tacoma hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Tacoma with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Tacoma shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Tacoma uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Tacoma (and only Tacoma) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Tacoma's Scheduling Share for such hour. The MW amount of Tacoma's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Tacoma's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Tacoma shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Tacoma on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Tacoma of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Tacoma no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Tacoma no later than 0930 hours

on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Tacoma shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Tacoma shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Tacoma shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and

other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Tacoma's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Tacoma's schedule exceeds Tacoma's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Tacoma information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Tacoma in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges

other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Tacoma's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Tacoma's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Tacoma may elect to acquire a share of such Upgrade in an amount up to Tacoma's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Tacoma shall notify Bonneville in writing of Tacoma's decision regarding such acquisition. If Tacoma elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Tacoma's notice to Bonneville shall include the percentage of such Upgrade that Tacoma elects to acquire (Acquisition Percentage). If Tacoma fails to notify Bonneville within such 100-day period, Tacoma shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Tacoma elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Tacoma shall be Tacoma's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Tacoma shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Tacoma's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Tacoma and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership

Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Tacoma and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Tacoma may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Tacoma such portion of the Unacquired Share as has been apportioned to Tacoma pursuant to the Apportionment, and Bonneville shall offer to Tacoma such portion of the Unacquired Share.

(2) If Bonneville does not receive from Tacoma and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Tacoma and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = Tacoma's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Tacoma's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Tacoma shall

notify Bonneville in writing of Tacoma's decision regarding acquisition of the Additional Share Offered. If Tacoma fails to notify Bonneville within such 30-day period, Tacoma shall be deemed to have elected not to acquire any of the Additional Share Offered. If Tacoma elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Tacoma shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Tacoma elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Tacoma with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Tacoma pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Tacoma shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Tacoma has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Tacoma's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Tacoma's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Tacoma to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Tacoma in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Tacoma to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Tacoma's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Tacoma of the entire Agreement and of all of Tacoma's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Tacoma of this Agreement or of any of Tacoma's rights under this Agreement as

security for any indebtedness, whether present or future, of Tacoma pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Tacoma and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Tacoma has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Tacoma shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Tacoma transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Tacoma shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC

Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Tacoma's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Tacoma in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Tacoma in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Tacoma's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement

Cost for such Reinforcement between Bonneville and Tacoma based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Tacoma have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Tacoma pursuant to this subsection 7(d) shall not be payable by Tacoma pursuant to this Agreement.

(e) Bonneville shall provide Tacoma notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on Tacoma's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Tacoma's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Tacoma's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Tacoma's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c),

or 11(a) without Tacoma's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Tacoma hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Tacoma shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Tacoma in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Tacoma for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Tacoma shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Tacoma agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Tacoma, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Tacoma shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Tacoma, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of

Bonneville and Tacoma agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Tacoma pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Tacoma pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Tacoma a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Tacoma shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Tacoma, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to

the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Tacoma agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Tacoma pursuant to paragraph 9(a)(1), Bonneville shall bill Tacoma on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Tacoma shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Tacoma pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Tacoma on the monthly power bill, and Tacoma shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being

hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Tacoma the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Tacoma written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Tacoma an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in

Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Tacoma on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Tacoma shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Tacoma an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B,

D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to Tacoma on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Tacoma shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Tacoma pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Tacoma or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Tacoma on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Tacoma shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Tacoma the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Tacoma an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Tacoma such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Tacoma shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Tacoma an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Tacoma such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Tacoma shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Tacoma pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term

"AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Tacoma for wheeling provided pursuant to section 3(b)(1)(C)(i) on Tacoma's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Tacoma shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Tacoma shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Tacoma's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Tacoma pursuant to section 4 without incurring any liability to Tacoma therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Tacoma of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Tacoma makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Tacoma shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Tacoma shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Tacoma pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Tacoma pursuant to this Agreement; provided, however that Tacoma's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect

to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Tacoma pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Tacoma pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Tacoma, in a lump sum, any refund due to Tacoma pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Tacoma pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Tacoma under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Tacoma by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Tacoma, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Tacoma from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Tacoma's power bill.

10. **TRANSMISSION LOSSES**

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Tacoma pursuant to this Agreement, Tacoma shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Tacoma and

Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Tacoma's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Tacoma's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Tacoma's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Tacoma's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Tacoma in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written

notice to Tacoma of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Tacoma for purposes of effectuating remedial actions pursuant to this section.

(b) **Tacoma's Responsibilities**

(1) Tacoma shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Tacoma's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm Tacoma's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Tacoma shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Tacoma's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Tacoma pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be

determined by dividing the amount of power scheduled by Tacoma on Tacoma's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Tacoma shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Tacoma's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Tacoma and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Tacoma pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Tacoma may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Tacoma fails to appoint a representative to the Committee, Tacoma waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Tacoma hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Light Division Superintendent

Alternate: Power Manager

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Power Manager
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Tacoma, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Tacoma, and Tacoma shall not have any obligation

pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection

13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Tacoma and Capacity Owners other than Tacoma and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss

factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for

documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Tacoma's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into

good faith negotiations with Tacoma and Capacity Owners other than Tacoma regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Tacoma's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Tacoma is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Tacoma shall act through the Committee. Each of Bonneville and Tacoma agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that

has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Tacoma,

respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Tacoma each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no

authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Tacoma shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Tacoma its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or

controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Tacoma or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Tacoma pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Tacoma's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B,

lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating

Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration

within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Tacoma, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one.

The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or

information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not

otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Tacoma and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months

after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Tacoma pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Tacoma pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Tacoma or any Capacity Owner other than Tacoma for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville

shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Tacoma a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Tacoma a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Tacoma as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Tacoma's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Tacoma.

(f) If an audit report provided to Bonneville by Tacoma pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any

inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Tacoma a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Tacoma a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Tacoma as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Tacoma's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Tacoma; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Tacoma shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Tacoma chooses not to participate in any audit undertaken by the Committee, then Tacoma shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits

shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Tacoma of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Tacoma is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Tacoma's books, records, and documents that directly pertain to the revenue reportable in Tacoma's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Tacoma shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Tacoma is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Tacoma has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or

energy to Tacoma or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Tacoma at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Tacoma may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Tacoma may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Tacoma may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Tacoma's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Tacoma has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Tacoma's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Tacoma's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Tacoma' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Tacoma's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Tacoma of the amount of the Refunded Lump Sum Payment.

If Tacoma elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would

inequitably allocate to Tacoma and Capacity Owners other than Tacoma, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Tacoma or any Capacity Owner other than Tacoma.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Tacoma may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Tacoma may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Tacoma may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Tacoma's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Tacoma has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Tacoma's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the

immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Tacoma of the amount of Refunded Lump Sum Payment.

If Tacoma elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Tacoma and Capacity Owners other

than Tacoma, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Tacoma or any Capacity Owner other than Tacoma.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Tacoma, and Capacity Owners other than Tacoma shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Tacoma in substantially the same position with respect to Tacoma's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Tacoma, and Capacity Owners other than Tacoma shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Tacoma, and Capacity Owners other than Tacoma reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such

Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Tacoma, and Capacity Owners other than Tacoma do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Tacoma and Capacity Owners other than Tacoma and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Tacoma, and Capacity Owners other than Tacoma are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Tacoma may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Tacoma's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Tacoma elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Tacoma shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-

PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Tacoma's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Tacoma a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Tacoma's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Tacoma's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Tacoma pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Tacoma to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Tacoma of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Tacoma's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Tacoma fails to

terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Tacoma shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Tacoma shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Tacoma and Capacity Owners other than Tacoma. If Bonneville and Tacoma do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Tacoma, and Tacoma shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final

basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Tacoma's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of

Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Tacoma and Capacity Owners other than Tacoma.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and Tacoma agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Power Manager
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. **WAIVER**

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. **MISCELLANEOUS**

(a) **Effect of Section Headings**

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Tacoma shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or

any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Tacoma an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Tacoma during the development or consideration of any offer to any Capacity Owner other than Tacoma to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Tacoma is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Tacoma's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the

case may be, by the Committee, and not by Tacoma acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September

Date September 27, 1994

City of Tacoma, Department of Public Utilities

By Mark Crisson

Name Mark Crisson
(Print/Type)

Title Director of Utilities

Date September 23, 1994

Approved as to form & legality:

Chief Asst. City Attorney

/s/ MARK BUBENIK
Chief Assistant City Attorney

Effective Date September 27, 1994

/s/ MARK CRISSON

Director of Utilities

September 23, 1994

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$KK)} * \%}{\text{725 MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	41 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual	(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1. Alvey (Marion-Alvey Caps)	$5,739		
2. Slatt (Loop in - Breaker)	3,044		
3. Grizzly (BPA Breakers)	11,044		
4. Loop into Slatt	656		
5. Malin-Meridian loop into Captain Jack	982		
6. Alvey Substation - BPA	8,168		
7. Dixonville - PacifiCorp	8,635		
8. Meridian - PacifiCorp	6,548		
9. Power System Control	3,575		
10. Alvey-Spencer - BPA	1,346		
11. Spencer-Dixonville - PacifiCorp	20,388		
12. Dixonville-Meridian - PacifiCorp	32,140		
SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent			
13. Captain Jack (BPA Breakers)	$14,335		
14. Captain Jack (Communication and Control)	5,100		
15. Captain Jack (Series Capacitors)	722		
16. Power System Control	5,596		
17. Captain Jack line to Oregon-Calif. border	5,724		
SUBTOTAL	$31,477		
50 PERCENT OF SUBTOTAL	15,739		
TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Tacoma's Capacity Ownership Share	=	41 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$8,815,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	0
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Tacoma submitted a letter of credit.

D. ADJUSTED LUMP SUM PAYMENT

1.	Tacoma's Capacity Ownership Share	=		41 MW
2.	Adjusted Capacity Ownership Price	X	$	
3.	Adjusted Lump Sum Payment[1]	=		
4.	Initial Lump Sum Payment	–		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Tacoma	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Tacoma	=		

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Tacoma receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Tacoma's Capacity Ownership Share	=		41 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Tacoma	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Tacoma	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Tacoma receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Tacoma receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Tacoma receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Tacoma's schedules for transactions transmitted on Tacoma's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Tacoma's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Tacoma, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Tacoma and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Tacoma and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Tacoma or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Tacoma or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Tacoma and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Tacoma has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Tacoma shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Tacoma shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Tacoma agrees as follows:

(1) Tacoma shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Tacoma shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Tacoma shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Tacoma shall, in all solicitations or advertisements for employees placed by or on behalf of Tacoma, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Tacoma shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Tacoma's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Tacoma shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Tacoma shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Tacoma shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Tacoma's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Tacoma is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Tacoma may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Tacoma as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Tacoma shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Tacoma shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Tacoma becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Tacoma may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Tacoma certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Tacoma agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Tacoma agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Tacoma to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Tacoma hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Tacoma further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Tacoma's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Tacoma shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Tacoma acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Tacoma agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Tacoma agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Tacoma and Bonneville shall, in concert with the Capacity Owners other than Tacoma, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III: Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Tacoma pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D; line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Tacoma shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1			
MFUs of the FCRTS	2			
Allocation factor (Line 1/Line 2)	3			
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4			
Bonneville's total system operations cost from rate case	5			
Operations functionalization factor (Line 4/Line 5)	6			
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7			
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8			

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1			
Total power scheduling cost from rate case	2			
Power scheduling cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Power Scheduling Costs				
Power scheduling direct costs	5			
Power scheduling indirect costs	6			
Power scheduling overhead costs	7			
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8			
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9			

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	_____	_____	_____
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(_____)	(_____)	(_____)
D. End of Term Costs	4	_____	_____	_____

Tacoma's Initial Transaction with California Utility

Name of parties:	Tacoma / Western Area Power Administration
Term of Contract	December 31, 2004
Date of Execution:	December 31, 1984
Amount of Transaction (MW):	41 MW, December through August 74 MW, September through November

AUTHENTICATED COPY Contract No. DE-MS79-94BP94522

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF SEATTLE, WASHINGTON

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Seattle's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the CITY OF SEATTLE, CITY LIGHT DEPARTMENT, (Seattle), a municipal corporation operating and existing under the laws of the state of Washington. Each of Bonneville and Seattle is sometimes referred to individually in this Agreement as "Party"; Bonneville and Seattle are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Seattle executed a Memorandum of Understanding, DE-MS79-91BP93467 , dated September 18, 1991, which, among other things, sets forth the principles for Seattle's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Seattle are executing an amendment to Contract No. DE-MS79-88BP91657 to provide Seattle with, among other things, network wheeling between the John Day Substation and Seattle's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Seattle agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Seattle's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Seattle) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Seattle) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Seattle pursuant to this Agreement, which percentage is determined by dividing Seattle's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Seattle pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Seattle pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Seattle's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with

the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Seattle to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Seattle.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Seattle for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Seattle for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Seattle's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Seattle pursuant to this Agreement, which percentage is determined by dividing Seattle's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Seattle's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Seattle.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Seattle until payment is made by Seattle pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Seattle pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Seattle written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Seattle pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H,

and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Seattle, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Seattle purchases from Bonneville and Bonneville sells to Seattle the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, Seattle shall notify Bonneville in writing of Seattle's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Seattle shall have the right to utilize its Scheduling Share pursuant to the paragraph Seattle elects. Prior to Bonneville's receipt of such notification, Seattle shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Seattle fails to make an election within the prescribed time period, Seattle shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) No Third Party Wheeling

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Seattle shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Seattle does not own at the California-Oregon border or for which transmission Seattle receives any revenue that would be reportable in

Seattle's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Seattle's Scheduling Share is not fully utilized by Seattle in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Seattle's Scheduling Share for such hour but no longer than such hour. Seattle shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Seattle's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Seattle has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Seattle's Scheduling Share. In return for Seattle's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Seattle

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Seattle's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-

north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Seattle's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Seattle's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Seattle's Scheduling Share for such hour is less than the MW amount of the aggregate of Seattle's net firm transactions identified by Seattle to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Seattle's firm transactions that equals the difference between Seattle's Scheduling Share for such hour and the

MW amount of the aggregate of Seattle's firm transactions for such hour up to, but not in excess of, Seattle's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Seattle is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Seattle shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Seattle pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Seattle pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Seattle or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Seattle shall identify such firm transaction to Bonneville. Seattle shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Seattle's contract for such firm transaction (after information considered proprietary by Seattle has been redacted by Seattle). Bonneville shall review such contract to verify that the transaction is firm. If Seattle and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Seattle retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Seattle may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Seattle. Seattle shall have no obligation under this Agreement to make available to Bonneville any portion of Seattle's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Seattle's Scheduling Share without Seattle's prior consent.

(B) Seattle hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Seattle with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Seattle shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Seattle uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Seattle (and only Seattle) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Seattle's Scheduling Share for such hour. The MW amount of Seattle's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Seattle's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Seattle shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Seattle on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Seattle of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Seattle no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Seattle no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Seattle shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Seattle shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Seattle shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of

coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Seattle's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Seattle's schedule exceeds Seattle's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. **UPGRADES**

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Seattle information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Seattle in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Seattle's Capacity Ownership Percentage multiplied

by the MW amount of such Upgrade and (B) Seattle's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Seattle may elect to acquire a share of such Upgrade in an amount up to Seattle's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Seattle shall notify Bonneville in writing of Seattle's decision regarding such acquisition. If Seattle elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Seattle's notice to Bonneville shall include the percentage of such Upgrade that Seattle elects to acquire (Acquisition Percentage). If Seattle fails to notify Bonneville within such 100-day period, Seattle shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Seattle elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Seattle shall be Seattle's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Seattle shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Seattle's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Seattle and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Seattle and each of such other Capacity Owners

have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Seattle may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Seattle such portion of the Unacquired Share as has been apportioned to Seattle pursuant to the Apportionment, and Bonneville shall offer to Seattle such portion of the Unacquired Share.

(2) If Bonneville does not receive from Seattle and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Seattle and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = Seattle's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Seattle's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Seattle shall notify Bonneville in writing of Seattle's decision regarding acquisition of the Additional Share Offered. If Seattle fails to notify Bonneville within such 30-day period, Seattle shall be deemed to have elected not to acquire any of the Additional Share

Offered. If Seattle elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Seattle shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Seattle elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Seattle with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Seattle pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Seattle shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Seattle has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Seattle's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Seattle's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Seattle to any person without Bonneville's prior and express written consent. Such consent shall not be

unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Seattle in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Seattle to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Seattle's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Seattle of the entire Agreement and of all of Seattle's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Seattle of this Agreement or of any of Seattle's rights under this Agreement as security for any indebtedness, whether present or future, of Seattle pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Seattle and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Seattle has defaulted in the

performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Seattle shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Seattle transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Seattle shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Seattle's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie,

and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Seattle in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Seattle in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Seattle's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Seattle based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this

subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Seattle have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Seattle pursuant to this subsection 7(d) shall not be payable by Seattle pursuant to this Agreement.

(e) Bonneville shall provide Seattle notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on Seattle's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Seattle's interests to the extent such interests have been expressed to Bonneville in writing.

8. **EXISTING AGREEMENTS**

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Seattle's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Seattle's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Seattle's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Seattle hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements

with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Seattle shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Seattle in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Seattle for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Seattle shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Seattle agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of

Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Seattle, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Seattle shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Seattle, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Seattle agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Seattle pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Seattle pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Seattle a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and

such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Seattle shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Seattle, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Seattle agrees

that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Seattle pursuant to paragraph 9(a)(1), Bonneville shall bill Seattle on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Seattle shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Seattle pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Seattle on the monthly power bill, and Seattle shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual

Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Seattle the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Seattle written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Seattle an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast

Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Seattle on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Seattle shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Seattle an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant

Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to Seattle on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Seattle shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Seattle pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of

the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Seattle or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Seattle on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Seattle shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the

forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Seattle the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Seattle an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Seattle such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Seattle shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Seattle an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent

of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Seattle such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Seattle shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Seattle pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate

shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Seattle for wheeling provided pursuant to section 3(b)(1)(C)(i) on Seattle's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Seattle shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Seattle shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Seattle's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Seattle pursuant to section 4 without incurring

any liability to Seattle therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Seattle of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Seattle makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Seattle shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Seattle shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Seattle pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Seattle pursuant to this Agreement; provided, however that Seattle's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Seattle pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the

month in which such payment becomes due to Seattle pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Seattle, in a lump sum, any refund due to Seattle pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Seattle pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Seattle under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Seattle by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Seattle, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Seattle from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Seattle's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Seattle pursuant to this Agreement, Seattle shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Seattle and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Seattle's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Seattle's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Seattle's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Seattle's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Seattle in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Seattle of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by

Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Seattle for purposes of effectuating remedial actions pursuant to this section.

(b) **Seattle's Responsibilities**

(1) Seattle shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Seattle's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm Seattle's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Seattle shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Seattle's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Seattle pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Seattle on Seattle's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Seattle shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Seattle's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Seattle and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Seattle pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Seattle may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Seattle fails to appoint a representative to the Committee, Seattle waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Seattle hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Director, Power Management Division

Alternate: Manager, Resource Operations

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee

pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Seattle, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Seattle, and Seattle shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for

each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Seattle and Capacity Owners other than Seattle and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily

available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee

and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its

receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which

Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an

Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such

Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Seattle's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the

Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Seattle and Capacity Owners other than Seattle regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such

recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners

with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Seattle's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Seattle is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Seattle shall act through the Committee. Each of Bonneville and Seattle agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator

within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Seattle, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the

arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Seattle each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan

becomes effective pursuant to subsection 13(j), then Seattle shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Seattle its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning

any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Seattle or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Seattle pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Seattle's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation

Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Seattle, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the

name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as

amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes

regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is

made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Seattle and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15

equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Seattle pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Seattle pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Seattle or any Capacity Owner other than Seattle for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Seattle a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either

(A) render to Seattle a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Seattle as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Seattle's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Seattle.

(f) If an audit report provided to Bonneville by Seattle pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Seattle a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted

Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Seattle a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Seattle as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Seattle's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Seattle; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to

the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Seattle shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Seattle chooses not to participate in any audit undertaken by the Committee, then Seattle shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Seattle of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Seattle is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Seattle's books, records, and documents that directly pertain to the revenue reportable in Seattle's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Seattle shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Seattle is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Seattle has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Seattle or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Seattle at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Seattle may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Seattle may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Seattle may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Seattle's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Seattle has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Seattle's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + I = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Seattle's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Seattle' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which

Bonneville receives Seattle's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Seattle of the amount of the Refunded Lump Sum Payment.

If Seattle elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to Seattle and Capacity Owners other than Seattle, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Seattle or any Capacity Owner other than Seattle.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and

if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Seattle may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Seattle may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Seattle may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Seattle's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Seattle has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Seattle's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal

monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Seattle of the amount of Refunded Lump Sum Payment.

If Seattle elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Seattle and Capacity Owners other than Seattle, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Seattle or any Capacity Owner other than Seattle.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval

to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Seattle, and Capacity Owners other than Seattle shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Seattle in substantially the same position with respect to Seattle's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Seattle, and Capacity Owners other than Seattle shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Seattle, and Capacity Owners other than Seattle reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Seattle, and Capacity Owners other than Seattle do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Seattle and Capacity Owners other than Seattle and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Seattle, and Capacity Owners other than Seattle are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Seattle may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Seattle's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Seattle elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Seattle shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Seattle's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Seattle a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Seattle's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered

by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Seattle's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Seattle pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Seattle to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Seattle of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Seattle's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Seattle fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Seattle shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final

basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Seattle shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Seattle and Capacity Owners other than Seattle. If Bonneville and Seattle do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Seattle, and Seattle shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Seattle's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses

incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Seattle and Capacity Owners other than Seattle.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and Seattle agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) Amendments

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of

dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Seattle shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Seattle an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Seattle during the development or consideration of any offer to any Capacity Owner other than Seattle to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Seattle is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Seattle's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Seattle acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By _____
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September 27, 1994

Date September 27, 1994

The City of Seattle

By _____

/s/ ROBERTA PALM BRADLEY

Name Roberta Palm Bradley
(Print/Type)

Title Superintendent

Superintendent

Date September 23, 1994

September 23, 1994

Effective Date September 27, 1994

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment, if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$(XX)) * \%}}{\text{725 MW * \# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent), shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	160 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual		(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Seattle's Capacity Ownership Share	=	160 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$34,400,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Seattle. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Seattle's Capacity Ownership Share	=	160 MW
2.	Adjusted Capacity Ownership Price	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Seattle	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Seattle	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Seattle receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Seattle's Capacity Ownership Share	=		160 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Seattle	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Seattle	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Seattle receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Seattle receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Seattle receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Seattle's schedules for transactions transmitted on Seattle's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Seattle's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976) Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	180 MVAR Reactor Bank No. 1	100	100
	• Breaker D#4222	100	100
	• Isolating Switch D#4060	100	100
	• Associated Arresters	100	100
	300 MVAR Reactor Bank No. 2	100	100
	• Breaker D#4720	100	100
	• Isolating Switch D#4719	100	100
	• Associated Arresters	100	100
	• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
	• Breaker D#4038	100	100
	• Isolating Switch D#4062	100	100
	• Neutral isolating switch D#4109/4081	100	100
	• Associated Arresters	100	100
	• Associated PTs	100	100
	• North Main Bus 500 kV PTs	100	100
	• South Main Bus 500 kV PTs	100	100
	Station General		
9.	**Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
	Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
10.	**Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
11.	**Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Seattle, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Seattle and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Seattle and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Seattle or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Seattle or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Seattle and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Seattle has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Seattle shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Seattle shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Seattle agrees as follows:

(1) Seattle shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Seattle shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Seattle shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Seattle shall, in all solicitations or advertisements for employees placed by or on behalf of Seattle, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Seattle shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Seattle's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Seattle shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Seattle shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Seattle shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Seattle's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Seattle is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Seattle may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Seattle as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Seattle shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Seattle shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Seattle becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Seattle may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Seattle certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Seattle agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Seattle agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Seattle to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Seattle hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Seattle further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Seattle's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Seattle shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Seattle acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Seattle agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Seattle agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Seattle and Bonneville shall, in concert with the Capacity Owners other than Seattle, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Seattle pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Seattle shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Seattle's Initial Transaction with California Utility

Name of parties:	(1) Seattle / Pacific Gas & Electric Company
	(2) Seattle / Northern California Power Agency
Term of Contract:	(1) March 16, 2003
	(2) March 16, 2013
Date of Execution:	(1) March 16, 1993
	(2) March 16,1993
Amount of Transaction (MW):	(1) 100 MW
	(2) 60 MW

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1			
Total power scheduling cost from rate case	2			
Power scheduling cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Power Scheduling Costs				
Power scheduling direct costs	5			
Power scheduling indirect costs	6			
Power scheduling overhead costs	7			
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8			
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9			

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	_____	_____	_____
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(_____)	(_____)	(_____)
D. End of Term Costs	4	_____	_____	_____

AMENDATORY AGREEMENT

to the

PACIFIC NORTHWEST AC INTERTIE

CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUGET SOUND POWER& LIGHT COMPANY

Section Page

1. Definitions 2
2. Amendment of Agreement 2

This AMENDATORY AGREEMENT is executed as of Dec 20 1996, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PUGET SOUND POWER & LIGHT COMPANY **(Puget),** a corporation of the State of Washington.

WI TN ES SETH:

WHEREAS the Parties on October 11, 1994, entered into the Pacific Northwest (PNW) AC Intertie Capacity Ownership Agreement, Contract No. DE-MS79-94BP94521 (Agreement); and

WHEREAS the Federal Energy Regulatory Commission (FERC) has issued Order No. 888, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities And Transmitting Utilities"; and

WHEREAS the Parties desire to amend the Agreement so as to comply with such Order No. 888,

NOW, THEREFORE, the Parties agree as follows:

1. DEFINITIONS

Capitalized terms used in this Amendatory Agreement, unless otherwise defined herein, have the respective meanings set forth for such terms in the Agreement.

2. AMENDMENT OF AGREEMENT

Subsection 3(b) of the Agreement is deleted in its entirety and the following is inserted in lieu thereof

(b) Right to Wheel for Third Parties

Puget may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Puget. Puget shall have no obligation under this Agreement to make available to Bonneville any portion of Puget's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Puget's Scheduling Share without Puget's prior written consent.

Bonneville shall treat all scheduling information consistent with the standards of conduct contained in Part 37 of **FERC's** regulations.

IN WITNESS WHEREOF, the Parties hereto have executed this **Amendatory** Agreement.

PUGET SOUND POWER& LIGHT **COMPANY**

By Wayman Robinett

Name Wayman Robinett
(Print/Type)

Title Manager Transmission

Date Dec 20, 1996

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Clifford C. Perkins

Name Clifford C. Perkins
(Print/Type)

Title SR. Acct Ex.

Date 12-20-1996

PUGET POWER

December 23, 1996

Group Vice President for Marketing,
Conservation and Production
Bonneville Power Administration
905 NE 1 lth Avenue
Portland, OR 97232

Attention: Cliff Perigo
Senior Account Executive

Subject: Amendment to Puget Sound Power& Light Company (Puget) PNW AC Intertie Capacity Ownership Agreemeut

Dear Mr. Perigo:

Enclosed for your signature are two original copies, each signed by Puget, of an Amendatory Agreement to Puget's PNW AC Intertie Capacity Ownership Agreement, Contract No. DE-MS79-94BP94521. On December 20, 1996, Puget and Bonneville Power Administration entered into the Amendatory Agreement by signing and exchanging a facsimile copy of the enclosed originals.

This amendment was requested by Puget in order to meet the requirement that public utilities that jointly own interstate transmission facilities with non-jurisdictional utilities offer transmission service over their share of the joint facilities. The requirement is contained in the Federal Energy Regulatory Commission Order No. 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities."

Please sign both originals and return one set to Puget.

Sincerely,

Puget Sound Power & Light Company

By Wayman L Robinett
Wayman L. Robinett
Its: Manager, Transmission

Enclosures

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94521

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUGET SOUND POWER & LIGHT COMPANY

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Puget's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of October 11, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and PUGET SOUND POWER & LIGHT COMPANY (Puget), a corporation of the state of Washington. Each of Bonneville and Puget is sometimes referred to individually in this Agreement as "Party"; Bonneville and Puget are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Puget executed a Memorandum of Understanding, DE-MS79-91BP93466, dated September 18, 1991, which, among other things, sets forth the principles for Puget's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Puget are executing Contract No. DE-MS79-94BP93947 to provide Puget with, among other things, network wheeling between the John Day Substation and Puget's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Puget agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Puget) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Puget) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Puget pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with

the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Puget to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Puget.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Puget's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Puget.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the later of (1) the date of execution and delivery of this Agreement by both of the Parties, and (2) the date by which this Agreement has, with respect to Puget, been approved, accepted for filing or otherwise permitted to become effective by FERC; provided, that if FERC approves this Agreement for filing or otherwise permits this Agreement to become effective with any change or new condition, this Agreement shall not be or become effective unless both of the Parties have agreed in writing, and until the date by which both of the Parties have so agreed to such change or new condition. To the extent Puget is required to submit this Agreement to FERC, Puget shall submit this Agreement to FERC for approval no later than three Working Days after the date on which this Agreement is executed and delivered by both Parties. Bonneville shall provide Puget with a copy of the executed Agreement on the next Working Day after Bonneville executes the Agreement. Without limiting any of the foregoing, Puget shall use best efforts to obtain from FERC on the earliest possible date (following the date on which Puget is required to submit this Agreement to FERC pursuant to this subsection 2(a)) FERC's acceptance for filing or permission that this Agreement become effective in accordance with this subsection 2(a). This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All

liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Puget until payment is made by Puget pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Puget pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Puget written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Puget pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Puget, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Puget purchases from Bonneville and Bonneville sells to Puget the Capacity Ownership Rights.

(b) **Right to Wheel for Third Parties**

No later than 30 days after the Effective Date, Puget shall notify Bonneville in writing of Puget's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Puget shall have the right to utilize its Scheduling Share pursuant to the paragraph Puget elects. Prior to Bonneville's receipt of such notification, Puget shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Puget fails to make an election within the prescribed time period, Puget shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Puget shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Puget does not own at the California-Oregon border or for which transmission Puget receives any revenue that would be reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Puget's Scheduling Share is not fully utilized by Puget in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Puget's Scheduling Share for such hour but no longer than such hour. Puget shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Puget's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Puget has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis,

any transaction for such hour on any MW amount of Puget's Scheduling Share. In return for Puget's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Puget

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Puget's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Puget's Scheduling Share for such hour is less than the MW amount of the aggregate of Puget's net firm transactions identified by Puget to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Puget's firm transactions that equals the difference between Puget's Scheduling Share for such hour and the MW amount of the aggregate of Puget's firm transactions for such hour up to, but not in excess of, Puget's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Puget is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Puget shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section

3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Puget or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Puget shall identify such firm transaction to Bonneville. Puget shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Puget's contract for such firm transaction (after information considered proprietary by Puget has been redacted by Puget). Bonneville shall review such contract to verify that the transaction is firm. If Puget and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the

mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Puget retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Puget may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Puget. Puget shall have no obligation under this Agreement to make available to Bonneville any portion of Puget's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Puget's Scheduling Share without Puget's prior consent.

(B) Puget hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Puget with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Puget shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Puget uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four

months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Puget (and only Puget) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Puget's Scheduling Share for such hour. The MW amount of Puget's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Puget's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Puget shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) Preschedules

(A) Bonneville shall make available to Puget on each Working Day as soon as practicable after 0800 hours

information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Puget of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Puget shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Puget shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Puget shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Puget's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Puget's schedule exceeds Puget's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. **UPGRADES**

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Puget information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Puget in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Puget's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Puget may elect to acquire a share of such Upgrade in an amount up to Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Puget shall notify Bonneville in writing of Puget's decision regarding such acquisition. If Puget elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Puget's notice to Bonneville shall include the percentage of such Upgrade that Puget elects to acquire (Acquisition Percentage). If

Puget fails to notify Bonneville within such 100-day period, Puget shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Puget elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Puget shall be Puget's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Puget's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Puget and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Puget may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Puget such portion of the Unacquired Share as has been apportioned to Puget pursuant to the Apportionment, and Bonneville shall offer to Puget such portion of the Unacquired Share.

(2) If Bonneville does not receive from Puget and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period

specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A + B) \times C$

where: A = Puget's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Puget's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Puget shall notify Bonneville in writing of Puget's decision regarding acquisition of the Additional Share Offered. If Puget fails to notify Bonneville within such 30-day period, Puget shall be deemed to have elected not to acquire any of the Additional Share Offered. If Puget elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Puget shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Puget elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Puget with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94

rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Puget pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Puget has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Puget's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Puget's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Puget to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has

contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Puget in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Puget to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Puget's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Puget of the entire Agreement and of all of Puget's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Puget of this Agreement or of any of Puget's rights under this Agreement as security for any indebtedness, whether present or future, of Puget pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Puget and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Puget has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Puget shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Puget transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Puget shall give Bonneville written notice of such transfer, sale, alienation,

or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Puget in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability

change substantially, Bonneville shall notify Puget in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Puget's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Puget based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Puget have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Puget pursuant to this subsection 7(d) shall not be payable by Puget pursuant to this Agreement.

(e) Bonneville shall provide Puget notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on

Puget's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Puget's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Puget's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Puget's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Puget hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Puget shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Puget in accordance with the provisions of this section 9.

(a) **Lump Sum Payment**

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Puget for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Puget shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Puget agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Puget, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the

Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Puget agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Puget pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Puget pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California,

PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Puget a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to

which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Puget agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Puget pursuant to paragraph 9(a)(1), Bonneville shall bill Puget on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Puget shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Puget pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Puget on the monthly power bill, and Puget shall pay, pursuant to Exhibit B,

forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End

of Term Costs for the Fiscal Year, Bonneville shall refund to Puget the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Puget written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Puget an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast

End of Term Costs for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Puget pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but

excluding) the date of refund to Puget or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Puget on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Puget shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Puget the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual

Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Puget an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Puget pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Puget for wheeling provided pursuant to section 3(b)(1)(C)(i) on Puget's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Puget shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Puget shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Puget's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Puget pursuant to section 4 without incurring any liability to Puget therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Puget of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Puget makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Puget shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced

by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Puget shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Puget pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Puget pursuant to this Agreement; provided, however that Puget's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Puget pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Puget pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Puget, in a lump sum, any refund due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Puget under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Puget by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Puget,

(B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Puget from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Puget's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Puget pursuant to this Agreement, Puget shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Puget and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Puget's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Puget's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Puget's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Puget's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Puget in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Puget of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Puget for purposes of effectuating remedial actions pursuant to this section.

(b) Puget's Responsibilities

(1) Puget shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Puget's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville

may perform engineering analyses to confirm Puget's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Puget shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Puget's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Puget pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Puget on Puget's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Puget shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Puget's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Puget and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Puget pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Puget may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Puget fails to appoint a representative to the Committee, Puget waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Puget hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Vice President Power Planning

Alternate: Manager Power Contracts

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any

request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Puget, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. **OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN**

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Puget, and Puget shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a

planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Puget and Capacity Owners other than Puget and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the

costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such

request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional

documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting

documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan

(either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Puget's rights

and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Puget and Capacity Owners other than Puget regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan

is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Puget's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Puget is obligated to pay pursuant to the terms and conditions of this

Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Puget shall act through the Committee. Each of Bonneville and Puget agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Puget, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the

Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Puget each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Puget shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Puget its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or

controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Puget or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Puget pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Puget's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B,

lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating

Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration

within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Puget, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one.

The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or

information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not

otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Puget and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months

after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Puget pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Puget pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Puget or any Capacity Owner other than Puget for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville

shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Puget.

(f) If an audit report provided to Bonneville by Puget pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any

inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Puget; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Puget shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Puget chooses not to participate in any audit undertaken by the Committee, then Puget shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards.

Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Puget of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Puget is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Puget's books, records, and documents that directly pertain to the revenue reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Puget shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Puget is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Puget has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Puget or by a seller of power or energy, which power or energy is not

resource-specific and is delivered to Puget at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Puget may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Puget's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Puget' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Puget's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Puget of the amount of the Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would

inequitably allocate to Puget and Capacity Owners other than Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Puget may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the

immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Puget of the amount of Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Puget and Capacity Owners other than

Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Puget in substantially the same position with respect to Puget's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Puget, and Capacity Owners other than Puget reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject

to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Puget, and Capacity Owners other than Puget do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Puget and Capacity Owners other than Puget and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Puget, and Capacity Owners other than Puget are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Puget may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Puget elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Puget shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-

PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Puget a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Puget's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Puget's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Puget pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Puget to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Puget of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Puget's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Puget fails to

terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Puget shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Puget shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Puget and Capacity Owners other than Puget. If Bonneville and Puget do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Puget, and Puget shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis.

Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Puget's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of

Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Puget and Capacity Owners other than Puget.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. **RULES OF LAW**

(a) Bonneville and Puget agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. **WAIVER**

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. **MISCELLANEOUS**

(a) **Effect of Section Headings**

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Puget shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or

any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Puget an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Puget during the development or consideration of any offer to any Capacity Owner other than Puget to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Puget is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Puget's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Puget acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

October 11, 1994

Date October 11, 1994

Puget Sound Power & Light Company

By J R Lauckhart

/s/ J. R. LAUCKHART

Name J. R. Lauckhart
(Print/Type)

Title VP Power Planning

Vice President, Power Planning

Date 9/26/94

September 26, 1994

Effective Date _____

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the n transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meri

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$000)} * \%}{\text{725 MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacement Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 1 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	400 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual		(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$86,000,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Puget. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Adjusted Capacity Ownership Price	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Puget receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$
3.	Current Revised Adjusted Lump Sum Payment[1]	=	
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-	_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Puget receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Puget receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Puget receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Puget's schedules for transactions transmitted on Puget's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Puget's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: 'PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Puget, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation; liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Puget and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Puget and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Puget or its subcontractor, if any, under any such contract

or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Puget or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Puget and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If , during any 12-month period (including the 12 months preceding the award of this contract), Puget has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Puget shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Puget shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Puget agrees as follows:

(1) Puget shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Puget shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Puget shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Puget shall, in all solicitations or advertisements for employees placed by or on behalf of Puget, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Puget shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Puget's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Puget shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Puget shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Puget shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs

(OFCCP) for purpose of investigation to ascertain Puget's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Puget is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Puget may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Puget as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Puget shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Puget shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Puget becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Puget may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Puget certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Puget agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Puget agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Puget to fund its activities pursuant to

this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Puget hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Puget further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Puget's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Puget shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Puget acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Puget agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et

seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Puget agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Puget and Bonneville shall, in concert with the Capacity Owners other than Puget, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective equipment (such as grounding devices; reactors; arrestors and resistors;

voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that Capacity Owners pay only transmission-related system operations costs. The

operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation of the Federal transmission system; load, frequency, and voltage control of

Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed

activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; pollution control and

abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following

activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities undertaken by Bonneville that are consistent with system maintenance

activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs

to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering);

and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Puget pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall

include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the

portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Puget shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		_____	
Total power scheduling cost from rate case	2		_____	
Power scheduling cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Power Scheduling Costs				
Power scheduling direct costs	5	_____	_____	_____
Power scheduling indirect costs	6	_____	_____	_____
Power scheduling overhead costs	7	_____	_____	_____
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	_____	_____	_____
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(_____)	(_____)	(_____)
D. End of Term Costs	4	_____	_____	_____

Puget's Initial Transaction with California Utility

Name of parties: Puget / Pacific Gas & Electric Company

Term of Contract: Variable

Date of Execution: October 25, 1991

Amount of Transaction (MW): 300 MW

DC NOB S>N 2005

Customer	Contract Number	MW
Bonneville Power Administration, Power Business Line	96MS-95363	100
Bonneville Power Administration, Power Business Line	96MS-95363	100
PacifiCorp (FPT)	DE-MS79-94BP94280	200

SALE AND EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF PASADENA

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This SALE AND EXCHANGE AGREEMENT, executed as of _____, 19__, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF PASADENA, CALIFORNIA (Pasadena), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Pasadena is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Pasadena, the City of Burbank (Burbank), the City of Glendale (Glendale), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which

provides, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Pasadena, Burbank, and Glendale; and

WHEREAS this Agreement and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Pasadena desires to purchase and Bonneville desires to sell surplus firm capacity with energy under the terms specified herein; and

WHEREAS Bonneville and Pasadena also desire to enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Term.

This Agreement, when executed, shall become effective at 2400 hours January 31, 1988, and shall terminate at 2400 hours on April 15, 2008;

provided, however, that no power sales may occur subsequent to January 31, 2008. All obligations incurred hereunder shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

2(a) "Agreement" means this sale and exchange agreement between Bonneville and Pasadena.

2(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

2(c) "Contract Demand" means the maximum hourly rate of delivery for surplus firm power when this Agreement operates as a sale, or for capacity when this Agreement operates as an Exchange. This amount is 6 MW for Block 1 and 6 MW for Block 2, and may be modified by Pasadena pursuant to section 4. However, Contract Demand, when used in subsection 7(d), shall mean 12 MW, as may be modified by Pasadena pursuant to section 4.

2(d) "Contract Year" means the year beginning at 2400 hours on June 30 and ending at 2400 hours the following June 30.

2(e) "Embedded Transmission Costs" means a charge equal to the Nonfirm Rate portion of Bonneville's IS-87 Southern Intertie Transmission Rate Schedule or successor rate to the extent Pasadena uses the Pacific Northwest-Pacific Southwest DC Intertie to provide Supplemental Energy to Bonneville; provided, however, that if the Nonfirm Rate portion of IS-87 or successor rate is terminated prior to the expiration of this Agreement, the Parties agree to use an equivalent substitute value calculated using the same methodology Bonneville used to derive the Nonfirm Rate portion of IS-87. Embedded Transmission Costs also shall include a charge equal to Bonneville's ET-87 Energy Transmission Rate Schedule or successor rate to the extent Pasadena provides Supplemental Energy either generated from its resources located outside of Los Angeles County or delivered to Pasadena's points of delivery located outside of Los Angeles County.

2(f) "Energy Account" means an account consisting of (i) monthly totals of the amount of Peaking Replacement Energy and Exchange Energy obligated to be delivered to Bonneville during each month, the delivery of which energy Bonneville has declined pursuant to the provisions of paragraph 7(e)(1), and (ii) the value of such declined energy for each month converted to mills/kWh pursuant to paragraph 7(e)(4). For each month there will be two values in the Energy Account: a total amount of energy declined and the value of such energy in mills/kWh.

2(g) "Exchange" means the capacity for energy exchange terms and conditions as described in this Agreement.

2(h) "Exchange Energy" for Block 1 as defined in subsection 5(a) means the energy Pasadena is obligated to deliver to Bonneville in equal weekly increments throughout the year in Exchange for Bonneville deliveries of capacity on an annual basis. Exchange Energy for Block 2 as defined in subsection 5(b) means the energy Pasadena is obligated to deliver to Bonneville during the period November 16 through April 15 in exchange for Bonneville making available capacity during the preceding May 15 through October 14 period.

2(i) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie transmission lines cross the Nevada-Oregon border.

2(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission capacity due to physical limitations, or (ii) the physical transmission capacity of the DC Intertie is reduced to zero for a period of time which is less than 24-consecutive hours.

2(k) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Pasadena during periods when this Agreement operates as an Exchange or capacity sale pursuant to Section 12.

2(l) "Peaking Replacement Energy" means an amount of energy which Pasadena is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

2(m) "PNW Coordination Agreement" means the contract among Bonneville and Pacific Northwest (PNW) generating entities, providing for coordinated operation of resources, designated as Contract No. 14-03-48221, as amended or replaced.

2(n) "Supplemental Energy" means the energy Pasadena is obligated to make available as a purchase option for Bonneville, pursuant to section 7.

2(o) "Total Incremental Cost" means incremental fuel cost, incremental operation and maintenance, generating unit start-up cost, transmission losses incurred by Pasadena in delivering Supplemental Energy to the Point of Delivery, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Pasadena in supplying Supplemental Energy to Bonneville that would not otherwise have been incurred.

2(p) "Total Outage" means the physical transmission capacity of the DC Intertie is reduced to zero, whether planned or unplanned, for a period of time which equals or exceeds 24-consecutive hours.

2(q)

"UIC" means any unrecoverable incremental costs beyond normal operations incurred by Pasadena in generating or acquiring

Supplemental Energy for which Bonneville rescinds its request pursuant to paragraph 7(c)(3). UIC includes, but is not limited to, direct costs, penalties, cancellation fees for fuel commitments, transmission services, or unrecoverable energy purchases, but excludes general engineering, scheduling, and administrative charges. UIC shall not include costs incurred by Pasadena to the extent that Pasadena is able to make use of such Supplemental Energy and in doing so mitigates costs it has incurred or avoids costs it would otherwise have incurred.

2(r) "Workday" means each day which both Bonneville and Pasadena observe as a regular workday.

3. Exhibits.

Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), General Contract Provisions (Form PSC (SW-1)) (Exhibit B), Plan of Delivery (Exhibit C), Minimum Monthly Energy Distribution Tables for Pasadena (Exhibit D), and Operating Procedures (Exhibit E) are attached hereto and hereby made a part of this Agreement.

4. Option for Pasadena to Increase Purchase.

Not later than June 1, 1988, Pasadena, Burbank, and Glendale may, upon written notice, increase their power purchase by a total of 60 MW, or more, if Bonneville determines power is available for this purpose.

To the extent that any such increase results in an increase for Pasadena pursuant to this Agreement, then that increase shall become effective for the Contract Year beginning at 2400 hours on June 30, 1988, and shall be distributed equally to Blocks 1 and 2 for both the surplus firm power sale and Exchange under this Agreement. This Agreement shall be amended as necessary to reflect such increase.

5. Surplus Firm Power Sale.

5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Pasadena shall purchase 7,610 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Pasadena shall purchase during each Contract Year 18,396 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Pasadena shall purchase during each Contract Year while this Agreement remains a power sale, 21,024 MWh of surplus firm energy.

5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Pasadena shall purchase 6,610 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing until 2400 hours on June 30, 1992, Pasadena shall purchase 2,030 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, and continuing until 2400 hours on October 14, 1992, Pasadena shall purchase 5,342 MWh of surplus firm energy. Beginning at 2400 hours on May 14, 1993, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Pasadena shall purchase 7,711 MWh of surplus firm energy.

5(c) Adjustments to Amount of Power.

The above MWh quantities for Pasadena shall be adjusted as necessary to account for any increase pursuant to section 4. However, in the event of a partial Contract Year power sale for Block 1, or in the

event of a partial May 15 through October 14 power sale for Block 2, Pasadena shall purchase the appropriate monthly amounts of surplus firm energy under Block 1 and under Block 2 as shown in the applicable plan of delivery for such Contract Year pursuant to subsection 5(e). Pasadena may increase the energy scheduled for purchase from Bonneville for any month under the then-current plan of delivery, if such energy is available as determined by Bonneville for such purpose. Such increases shall not affect the plan of delivery, the minimum monthly energy delivery in any future months during such Contract

Year, nor shall any such increase affect the take-or-pay energy amount in any future Contract Year.

5(d) Rates of Delivery.

The maximum hourly rates of delivery for surplus firm power shall be 6 MW from October 15 through May 14 and 12 MW from May 15 through October 14, as may be modified by Pasadena's option to increase pursuant to section 4.

5(e) Distribution of Monthly Amounts.

Prior to January 1 of each year, Pasadena shall submit a plan of delivery to Bonneville showing the distribution of the monthly amounts of energy for the following 4 Contract Years in the form represented by Exhibit C. Pasadena shall distribute the monthly amounts of energy within the limits indicated in Exhibit D.

5(e)(1) If requested by Pasadena, Bonneville shall consult with Pasadena at the time such plans of delivery are being prepared. Bonneville will share its most recent information on its ability to serve Pasadena with a power sale for the following 4 Contract Years and any other considerations that may relate to the plans of delivery. Bonneville shall include such plans of delivery in its PNW Coordination Agreement planning.

5(e)(2) The Parties shall rely upon the most recent plan of delivery submitted to Bonneville for the amount of energy to be delivered in the upcoming July. Bonneville shall notify Pasadena at the earliest opportunity, but not later than August 15, if other than that most recent proposed plan of delivery shall become effective for the balance of the Contract Year. Unless otherwise agreed by the Parties, notwithstanding the limits indicated in Exhibit D, the total of the monthly amounts Bonneville shall deliver during July and August shall equal the 2-month July and August total energy amount specified in the plan of delivery ultimately adopted for use during that Contract Year; provided, however, that in the event that Pasadena is unable to receive the minimum amount of energy during August due to the timing of such notice, then the Parties shall adjust deliveries as necessary prior to November 16 to provide for any energy not received during August.

5(e)(3) If Bonneville adopts a plan of delivery other than the most recent plan of delivery submitted, Bonneville shall adjust the adopted plan of delivery to reflect the most recent Intermountain Power Project scheduled maintenance outages.

5(f) Distribution of Weekly Amounts.

Within any month, Pasadena shall not take more than 135 percent of that month's average weekly amount in any Calendar Week. Such average weekly amount shall be equal to the total MWh for that month as specified in the applicable plan of delivery, divided by the number of days in that month, and multiplied by 7.

5(g) Operational Flexibility.

Pasadena may request changes of up to 5 percent of any monthly amount of energy to be made available under the Agreement, with no less than 2 months' advance written notice. Such changes shall not be unreasonably denied by Bonneville, and the ability to make such changes shall be at no additional cost to Pasadena. The effect of such changed monthly amount on subsequent monthly amounts of energy shall be included in this notice; provided, however, that changes in monthly amounts purchased hereunder shall not be reduced below the minimum monthly amounts of energy specified in Exhibit D, unless mutually agreed to by the Parties.

6. Conversion to the Exchange.

The sale of surplus firm power shall convert to the Exchange if Bonneville has a surplus firm energy insufficiency under the conditions described in this section; provided, however, that Pasadena shall have the option to either: (i) remain in the power sale mode

until after other similar long term sale and exchange agreements executed with parties outside of the Pacific Northwest region for which initial deliveries shall commence after January 1, 1988, have been converted to an exchange; or (ii) convert to the Exchange prior to the conversion of such other similar long term sale and exchange agreements. Pasadena shall exercise its option within 14 days after Pasadena receives Bonneville's written notice that it will be converting this Agreement or such other similar agreements to an exchange.

6(a) Preliminary Notice.

6(a)(1) If Bonneville determines in the PNW Coordination Agreement planning process that there is a possibility of insufficient surplus firm energy to satisfy the surplus firm energy obligation to Pasadena in the next Contract Year, Bonneville shall provide written notice to Pasadena as soon as possible. Following this notice, the Parties may, upon mutual agreement, begin the Exchange at 2400 hours on May 14 or on a subsequent date prior to 2400 hours on June 30 of the then-current Contract Year.

6(a)(2) If Bonneville determines in the planning process that there is a certainty of insufficient surplus firm energy for the next Contract Year, Bonneville shall provide written notice to Pasadena as soon as possible, but not later than June 15. In this event, regardless of the

ext

ent to which PNW system refill occurs, the Exchange shall begin at 2400 hours on June 30. Pasadena's Exchange Energy obligation for Block 2 shall be adjusted to account for a start date of July 1 rather than May 15.

6(b) Final Notice.

If the Exchange does not begin pursuant to subsection 6(a), then the provisions of this subsection apply. The completion of PNW Coordination Agreement planning and the adoption by Bonneville of a particular plan of delivery for Pasadena shall occur after July 31. Bonneville shall provide written notice to Pasadena as soon as possible after July 31, but not later than August 15, whether service at the Contract Demand shall continue as a power sale or convert to the Exchange. If such notice specifies a conversion to the Exchange, then the Exchange shall begin no sooner than 14 days after the date of receipt of such notice by Pasadena. Conversion to the Exchange shall be effective for the remainder of the Contract Year from the time specified in Bonneville's notice to Pasadena, or as provided for in subsection 6(c). Pasadena's Exchange Energy obligation shall be adjusted to account for the start date specified in the notice rather than May 15.

6(c) Reversion to Power Sale.

After conversion to the Exchange, whenever Bonneville determines that it has sufficient surplus firm energy to deliver the amounts

of surplus firm power specified in subsections 5(a) and 5(b) for the ensuing Contract Year, deliveries under this Agreement shall revert to the surplus firm power sale pursuant to section 5, unless Pasadena has provided written notice to Bonneville which describes a contract offer to acquire a resource to replace the energy no longer available from Bonneville due to the conversion to the Exchange. Such notice shall include the amount of energy to be acquired and the term of the proposed acquisition. Bonneville shall respond as follows:

Bonneville shall, within 21 days of receipt of such notice, notify Pasadena as to whether this transaction shall revert to the power sale for the duration of Pasadena's proposed energy acquisition. If this transaction is to revert to the power sale, Bonneville shall notify Pasadena of the basis for the reversion, and such power sale shall begin by the later of (1) 31 days from receipt by Bonneville of Pasadena's notice, or (2) the effective date of energy deliveries pursuant to Pasadena's proposed acquisition, and shall continue for the duration of Pasadena's acquisition, subject to the provisions of section 12. If Bonneville elects not to have the transaction revert to the power sale, then Bonneville shall waive its right to revert to the power sale for the duration of Pasadena's contractual commitment for the proposed energy acquisition. Prior to the termination of Pasadena's acquisition contract, Bonneville shall, upon written notice of at least 30 days, have the right to revert to the power sale as described in section 5 at the termination of Pasadena's acquisition.

6(d) The notice provisions of subsections 6(a) and 6(b) shall apply to reversion from Exchange to power sale, as well as the conversion from power sale to Exchange, except as may be modified by the provisions of subsection 6(c).

7. Capacity For Energy Exchange.

Upon conversion to the Exchange, Bonneville shall make 6 MW of capacity available to Pasadena for Block 1 on an annual basis and 6 MW of capacity for Block 2 from May 15 through October 14 each year, as may be modified by Pasadena's option to increase pursuant to section 4. Pasadena shall be obligated to deliver Peaking Replacement Energy to Bonneville during these periods of capacity deliveries as specified in subsection 7(a). In Exchange for Bonneville deliveries of capacity, Pasadena shall deliver Exchange Energy and make available Supplemental Energy to Bonneville, as specified in subsections 7(b) and 7(c).

7(a) Deliveries of Capacity and Peaking Replacement Energy.

At times when the Exchange is in effect, Bonneville shall make available to Pasadena capacity in an amount up to the Contract Demand each hour, up to 10 hours times the Contract Demand each day Monday through Saturday, including holidays, not to exceed 50 hours times the Contract Demand each week. Pasadena shall be obligated to deliver to Bonneville Peaking Replacement Energy for the amounts of Peaking Energy delivered to Pasadena by 2400 hours

on the day following the Peaking Energy delivery, except as provided in subsection 7(e). Return of Peaking Replacement Energy during any hour shall not exceed 100 percent of the Contract Demand in any hour, unless otherwise mutually agreed by the parties.

7(b) Exchange Energy.

Pasadena shall be obligated to deliver Exchange Energy to Bonneville as provided herein. The amount of such energy provided each Contract Year shall equal the exchange ratio in kWh/kW for each block of capacity, multiplied by the Contract Demand in kilowatts for each block of capacity. For Block 1, the exchange ratio is 2,536 kWh/kW; for Block 2, the exchange ratio is 975 kWh/kW. Exchange Energy for Block 1 shall be delivered in equal weekly increments throughout the year and Exchange Energy for Block 2 shall be delivered in equal weekly increments from November 16 through April 15, except as provided in subsection 7(e). Such equal weekly increments shall be adjusted as necessary to account for an uneven number of weeks during any Exchange Energy delivery period. In the event of a partial Contract Year of capacity deliveries, the amount of Exchange Energy which Pasadena is obligated to deliver to Bonneville shall be reduced on a pro rata basis to account for such partial Contract Year.

7(c) Supplemental Energy.

7(c)(1) Pasadena shall be obligated to make Supplemental Energy available to Bonneville during each November 16 through April 15 while this Agreement operates as an Exchange. The total amount of such energy provided each Contract Year shall equal the supplemental ratio in kWh/kW multiplied by the Block 2 Contract Demand in kilowatts of capacity. The supplemental ratio is 1,200 kWh/kW. Bonneville may elect to purchase up to the maximum amount of Supplemental Energy available to Bonneville in any Contract Year by serving a notice to Pasadena not less than 2 months prior to the desired delivery date, or on shorter notice if agreed to by Pasadena. Bonneville may issue additional notices during any Contract Year for amounts of Supplemental Energy not previously requested in a notice. Any such notice shall specify the amount of Supplemental Energy desired by Bonneville and provide a nonbinding proposed schedule for deliveries of Supplemental Energy. Pasadena shall promptly notify Bonneville if such proposed schedule is unacceptable to Pasadena and the reasons therefor. Pasadena shall not unreasonably deny Bonneville's proposed schedule. In the event that the Parties are unable to agree on a proposed schedule, then the requested Supplemental Energy shall be delivered in equal hourly increments during the delivery period specified in Bonneville's notice and during the

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rs specified in paragraph 7(d)(3). Bonneville and Pasadena shall finalize the schedule for deliveries of weekly blocks of Supplemental Energy within 15 Workdays of receipt by Pasadena of Bonneville's notice. Deliveries of Supplemental Energy are subject to Pasadena's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Pasadena's generation or transmission capability. In the event of any such constraints, Pasadena shall reschedule such deliveries in a timely manner. In the event of an extended generation constraint, Bonneville may request an alternate available source for Supplemental Energy at another agreed upon price, until such time as the generation constraint is removed.

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hin 15 Workdays of receipt of Bonneville's notice requesting to make available Supplemental Energy, and prior to committing to obtain Supplemental Energy, Pasadena shall inform Bonneville of probable resources available, including the estimated price of the lowest cost sources of Supplemental Energy available for purchase, the estimated Total Incremental Cost from such sources, and the UIC for such resources. Pasadena shall revise such estimated price, Total Incremental Cost, and UIC if conditions change substantially during the remaining days of the notice period described in

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agraph 7(c)(1). If Pasadena determines that the UIC from such sources will exceed 4.5 mills, as escalated pursuant to subsection 9(c), it shall notify Bonneville, and Bonneville shall have the option of either: (1) raising such maximum rate for UIC; (2) relieving Pasadena of its obligation to provide Supplemental Energy; or (3) obligating itself to purchase Supplemental Energy. Bonneville shall make this choice in a timely manner. Pasadena shall use best efforts to mitigate UIC, but unless earlier notification by Pasadena and Bonneville's selection of its option to raise the maximum rate for UIC has occurred, Bonneville's obligation for the amount of energy specified in its notice of rescission shall not exceed 4.5 mills/kWh as escalated pursuant to subsection 9(c).

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neville shall pay Pasadena any applicable Embedded Transmission Costs plus 115 percent of Pasadena's Total Incremental Cost for providing Supplemental Energy. Bonneville may rescind a notice requesting Supplemental Energy not later than 0930 hours of the Workday immediately preceding the day when such Supplemental Energy was to begin to be provided to Bonneville, and pay Pasadena any UIC incurred by Pasadena in response to Bonneville's previous request for such energy. Any decision to rescind a notice requesting Supplemental Energy shall apply to the total amount of MWh of

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plemental Energy requested by Bonneville pursuant to paragraph 7(c)(1); provided, however, that Bonneville can rescind a portion of the Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1) if Bonneville agrees to pay any new UIC resulting therefrom.

7(c)(4) Bonneville shall submit schedules for the delivery of Supplemental Energy pursuant to the provisions of paragraph 7(c)(1) and section 10. Pasadena shall not unreasonably withhold its agreement with such schedules, and Pasadena shall deliver weekly amounts of Supplemental Energy by the end of each Calendar Week during the period of deliveries pursuant to the mutually agreed upon schedules for the delivery of Supplemental Energy.

7(d) Delivery Limitations.

7(d)(1) May 15 through October 14.

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ess limited by Bonneville, Pasadena shall complete each Calendar Week's deliveries of Exchange Energy by the end of such Calendar Week. The maximum rate of delivery for Peaking Replacement Energy plus Exchange Energy shall be 100 percent of the Contract Demand. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account. Bonneville may limit the delivery rate for

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king Replacement Energy plus Exchange Energy to not less than 60 percent of Contract Demand for the Exchange during the period May 15 through October 14. To the extent that Bonneville restricts the delivery on any hour, the restricted quantity of Peaking Replacement Energy and Exchange Energy may either be delivered by Pasadena on hours other than the hours specified in paragraph 7(d)(3), or be delivered on the next available normal delivery hour when Bonneville can accept such energy. The Parties may agree to delay the delivery beyond the Calendar Week of delivery, or the Parties may agree to place such energy into the Energy Account, as described in paragraph 7(e)(1).

7(d)(2) November 16 through April 15.

Hourly rates of delivery shall be as mutually agreed upon by Bonneville and Pasadena. However, during the period November 16 through April 15, during any hour the total rate of delivery for Exchange Energy plus Supplemental Energy plus Peaking Replacement Energy shall not exceed 250 percent of the Contract Demand, unless mutually agreed to by Bonneville and Pasadena. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account.

7(d)(3) Normal Delivery Hours for Peaking Replacement and Exchange Energy.

Although deliveries of Peaking Replacement Energy and Exchange Energy may occur during other hours, the normal delivery hours are as follows:

2200 hours on Monday to 0800 hours on Tuesday
2200 hours on Tuesday to 0800 hours on Wednesday
2200 hours on Wednesday to 0800 hours on Thursday
2200 hours on Thursday to 0800 hours on Friday
2200 hours on Friday to 0800 hours on Saturday
2200 hours on Saturday to 0800 hours on Monday.

7(e) Conditions for Energy Account and Cash-Out of Peaking Replacement and Exchange Energy.

7(e)(1) Declinations of Peaking Replacement Energy and Exchange Energy.

Bonneville may decline deliveries of either Peaking Replacement Energy or Exchange Energy in whole or in part. Bonneville shall provide Pasadena with notice by 1400 hours on the Thursday prior to each Calendar Week. Such notice shall specify whether Bonneville will require the delivery of such energy in whole or in part for the next Calendar Week and shall specify the amount of energy which Bonneville declines. To the extent that Bonneville declines the deliveries, the monthly total of such declined energy and its value converted to mills/kWh

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suant to paragraph 7(e)(4) shall be entered into the Energy Account.

7(e)(2) Withdrawals from the Energy Account.

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neville may request to withdraw energy from the Energy Account during a Calendar Week and shall provide Pasadena with notice by 1400 hours on the Thursday prior to such Calendar Week. Such notice shall specify the quantity of energy to be withdrawn and the rate of delivery for such energy. However, in addition to other deliveries by Pasadena pursuant to this Agreement, the maximum rate of withdrawal from the Energy Account shall not exceed the Contract Demand on any hour, unless mutually agreed. Pasadena shall provide such requested energy to Bonneville during the next Calendar Week, subject to Pasadena's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Pasadena's generation or transmission capability. The value for energy withdrawn from the Energy Account shall be converted to kWh as determined pursuant to paragraph 7(e)(4) and shall be withdrawn on a first-in-first-out basis. To the extent that the value for withdrawn energy is greater than the value for declined energy determined pursuant to paragraph 7(e)(1), Bonneville shall pay Pasadena an amount equal to the

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ference between the values for withdrawn and declined energy multiplied by the kWh withdrawn. To the extent that the value for withdrawn energy is less than the value for declined energy determined pursuant to paragraph 7(e)(1), Pasadena shall pay Bonneville an amount equal to the difference between the values for declined and withdrawn energy multiplied by the kWh withdrawn. Each party shall pay the other pursuant to the provisions of section 8. If mutually agreed, withdrawn energy may be provided on hours other than those specified in paragraph 7(d)(3).

7(e)(3) Cash-Out of Energy in the Energy Account.

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neville shall maintain the Energy Account. The Energy Account shall contain monthly totals of (i) the declined energy remaining at the end of each calendar month, and (ii) the value of such energy converted to mills/kWh pursuant to paragraph 7(e)(4). Any monthly total of energy which remains in the Energy Account longer than 11 months shall be cashed out pursuant to subsection 9(b) at the cash-out price at the time the energy was entered into the Energy Account. No more than one monthly total of energy shall be cashed out on any monthly bill rendered to Pasadena. Pasadena shall pay Bonneville pursuant to the cash-out terms specified in subsection 9(b), and shall be relieved of any obligation

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reafter to provide such monthly total of energy to Bonneville.

7(e)(4) Determination of Value for Energy Entered into Energy Account and Withdrawn from Energy Account.

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lowing receipt of its gas bill each month, Pasadena shall provide Bonneville with a copy of a portion of such bill which shows the dollars per dekatherm paid by Pasadena for the total of all gas purchases for that month. Bonneville shall convert this amount to dollars per Btu and apply this ratio to an agreed-upon heat rate of 10,000 Btu per kWh to determine the value in mills per kWh for entries into and withdrawals from the Energy Account during the following month. To the extent that gas is not available or is no longer a significant fuel source for generation by Pasadena, the Parties shall negotiate: (i) an alternate significant fuel source which is used by Pasadena for generation; and (ii) a methodology to derive a value in mills/kWh for entries into and withdrawals from the Energy Account. This Agreement shall be amended to implement the results of such negotiation.

7(f) At Pasadena's request, the Parties agree to negotiate in good faith mutually agreeable terms and conditions which would allow Pasadena to deliver energy to Bonneville's system for later use by Pasadena.

8. Payment.

8(a) Payment by Pasadena.

Bonneville shall render preliminary and final adjusted monthly bills to Pasadena. Pasadena shall pay Bonneville by the close of business on the twentieth (20th) day after the date of each such preliminary bill and any adjustments that may occur on the final monthly bill. The date of such bills shall be no earlier than the mailing date of such bills. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Pasadena, then the due date shall be the next following business day. Other provisions related to payment of bills shall be in accordance with the General Rate Schedule Provisions attached to this Agreement.

8(b) Payment by Bonneville.

Pasadena shall render monthly bills to Bonneville. Bonneville shall pay Pasadena by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to payment of bills shall be in accordance with the General Rate Schedule provisions attached to this Agreement.

9. Rates and Cash-Out.

9(a) Surplus Firm Power.

9(a)(1) Initial Demand and Energy Rates.

The initial demand and energy rates for deliveries of power under Block 1 and Block 2 are as follows: $4.60/kilowatt-month (kW-mo.) and 20.5 mills/kWh (includes Intertie adder). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery.

9(a)(2) Rate Adjustment During First 5 Years.

The initial demand and energy rates for the period January 1, 1988, through December 31, 1988, are described in paragraph 9(a)(1). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. The energy rates specified in this paragraph 9(a)(2) include the Intertie adder. The rates for calendar years 1989 through 1992 are as follows:

Calendar Year	Capacity ($/kW-mo.)	Energy (mills/kWh)
1989	4.88	21.73
1990	5.17	23.03
1991	5.48	24.42
1992	5.81	25.88

Subsequent to December 31, 1992, the demand and energy rates shall be adjusted pursuant to paragraph 9(a)(3).

9(a)(3) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

Adjustments under this paragraph begin January 1, 1993. For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. On the effective date of any Bonneville Priority Firm Power (PF) rate adjustment thereafter, the rate for surplus firm power (SL_{new}) shall be adjusted as follows:

$$SL_{new} = SL_n * \frac{PF_{new}}{PF_{prev}}$$

where

SL_{new} = The effective surplus firm power demand and energy charges hereunder as adjusted to reflect the change between PF_{new} and PF_{prev}.

SL_n = For the initial adjustment under this paragraph 9(a)(3) the SL_n demand charge shall be $5.81/kW-mo. and the energy charge shall be 25.88 mills/kWh. For all subsequent adjustments under this paragraph, the values for SL_n shall be the then-current values for the previous SL_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be

determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh, in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(b) Cash-out.

Bonneville shall cash out energy pursuant to paragraph 7(e)(3). Pasadena shall pay Bonneville for such energy as provided below.

9(b)(1) Initial Cash-out.

The initial level for cash-out shall be 14.9 mills/kWh.

9(b)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any PF rate adjustment after the effective date of this Agreement, the level of the cash-out rate (CO_{new}) shall be adjusted as follows:

$$CO_{new} = CO_{n} * \frac{PF_{new}}{PF_{prev}}$$

where CO_{new} = The effective level for cash-out as adjusted to reflect a new PF rate.

CO_n = For the initial adjustment under this paragraph 9(b)(2), CO_n shall be 14.9 mills/kWh. For all subsequent adjustments under this paragraph, the values for CO_n shall be the then-current values for the previous CO_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(c) Maximum Rate for UIC Incurred by Pasadena if Bonneville Rescinds a Notice for Supplemental Energy.

9(c)(1) Initial Maximum Rate for UIC.

In accordance with subsection 7(c), the initial rate for UIC is 4.5 mills/kWh for the amount of energy specified in Bonneville's notice of rescission.

9(c)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any Priority Firm Power (PF) rate adjustment after the effective date of this

Agreement, the maximum rate for UIC (UIC_{new}) shall be adjusted as follows:

$$UIC_{new} = UIC_{n} * \frac{PF_{new}}{PF_{prev}}$$

where

UIC_{new} = The effective rate for UIC as adjusted to reflect a new PF rate.

UIC_{n} = For the initial adjustment under this paragraph 9(c)(2), UIC_{n} shall be equal to 4.5 mills/kWh. For all subsequent adjustments under this paragraph, the values for UIC_{n} shall be the then-current values for the previous UIC_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

10. Scheduling Provisions for Power Sale and Exchange.

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

10(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

10(b) Prescheduled amounts shall be submitted by 0930 hours.

10(c) This subsection 10(c) shall apply only to the power sale portion of this transaction. If Pasadena desires to schedule other than that month's average weekly amount of energy for such month in any Calendar Week, Pasadena shall notify Bonneville by 1400 hours on the Monday preceding such Calendar Week. Pasadena may revise such new weekly amount if Pasadena notifies Bonneville by 1400 hours on the Thursday preceding such Calendar Week.

10(d) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts that Pasadena anticipates it will schedule from Bonneville each day for the following 10 days. Pasadena shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Pasadena or Bonneville to schedule such amounts.

10(e) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such changes

shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

11. Transmission Limitation.

In the event of an interruption of deliveries by either Party due to a DC Intertie outage, the following provisions shall apply.

11(a) Relief Remedies During Periods of Total Outage.

The Parties shall be relieved of obligations as follows.

11(a)(1) Conditions for Capacity Payment Relief.

The following conditions must be met each Contract Year for relief to be given as described in paragraph 11(a)(2): (i) the duration of a single Total Outage exceeds 360-consecutive hours, in which case relief is provided for the remainder of such Total Outage only; or (ii) the sum of all Total Outages for the Contract Year exceeds 720 hours, excluding Total Outages, if any, for which relief was given pursuant to item (i) above.

11(a)(2) Determination of Capacity Payment Relief.

For the duration of the Total Outages which occur subsequent to the occurrence of relief as described in

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agraph 11(a)(1), Pasadena shall receive a capacity credit in the form of a reduction in the demand rate per kW-mo. calculated by determining such duration of the Total Outage during the billing month, divided by the total number of hours in that month.

11(a)(3) Energy Payment Relief During Power Sale.

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hout regard to the duration of a Total Outage, if Pasadena is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Pasadena shall be relieved of its obligation to pay for such amounts of energy. To the extent that Pasadena is unable to receive energy during any month, the monthly minimum take-or-pay energy specified in the applicable plan of delivery shall be reduced by an amount of energy determined as follows: a ratio shall be calculated, the numerator being the number of hours of Total Outage during the month that Pasadena is unable to receive energy, and the denominator being the total number of hours in that month. This ratio is then multiplied by the monthly energy specified in the applicable plan of delivery to determine such amount of energy. This amount of energy shall be subtracted from such monthly energy to determine the revised monthly amount for that month. The total take-or-pay energy for Block 1, or Block 2 if

app

licable, as specified in Exhibit D, shall be reduced by the amount of energy as calculated above.

11(a)(4) Energy Payment Relief During Exchange.

11(a)(4)(A) For Total Outages which occur subsequent to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Pasadena's obligation to deliver Peaking Replacement Energy owed to Bonneville for previous capacity delivered by Bonneville, and Supplemental Energy requested by Bonneville pursuant to subsection 7(c) remain. Pasadena's obligation to deliver Exchange Energy associated with a Total Outage up to one year remains, but, at Bonneville's option, either: (i) Pasadena shall deliver such energy to Bonneville subject to mutually agreed upon schedules following the end of the Total Outage and Bonneville shall pay Pasadena's Total Incremental Cost for the first 3 months of such obligation and 115 percent of Pasadena's Total Incremental Cost for the following 9 months; or (ii) Pasadena shall be relieved of its obligation to deliver such energy.

11(a)(4)(B) For Total Outages which occur prior to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Pasadena shall reschedule deliveries of Peaking Replacement Energy, Exchange Energy, and Supplemental Energy which Pasadena is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the Total Outage, or at other times as mutually agreed by the Parties.

11(b) Relief Remedies During Periods of Partial Outage.

11(b)(1) Relief Remedies During the Power Sale.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue deliveries under this Agreement. The Parties also shall curtail pro rata on an hourly basis all agreements executed on or before January 1, 1988, for firm energy or capacity based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over agreements executed after January 1, 1988 for firm energy or capacity. If Pasadena is unable to receive any amounts of energy, Bonneville shall be relieved of

its obligation to deliver and Pasadena shall be relieved of its obligation to pay for such amounts of energy.

11(b)(2) Relief Remedies During the Exchange.

During the Exchange, or during any period of the power sale when Bonneville has restricted surplus firm energy deliveries pursuant to section 12 and is delivering capacity only, the following provisions shall apply.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue or reschedule deliveries under this Agreement. The Parties shall curtail all agreements for firm capacity without energy or deliveries of exchange energy executed prior to January 1, 1988, pro rata on an hourly basis, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over deliveries of capacity or exchange energy pursuant to agreements executed after January 1, 1988. Pasadena shall reschedule interrupted or curtailed deliveries of Peaking Replacement Energy, Exchange Energy and Supplemental Energy which Pasadena is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the

interruption or curtailment, or at other times and under conditions as mutually agreed by the Parties.

12. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of 16 U.S.C. § 837 (1984) (P.L. 88-552), and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to those provisions, Bonneville shall have the right to restrict all or a portion of the capacity or energy if such capacity or energy is needed to meet the capacity or energy requirements, as the case may be, in the PNW. Such restrictions shall be limited in amounts and duration to cover the projected need specified in the written notice which Bonneville shall provide to Pasadena. Such written notice shall specify the date on which a period of restriction begins and the date on which such period of restriction is projected to end. The sale of surplus firm power shall resume pursuant to the applicable plan of delivery for the remainder of the then-current Contract Year after expiration of the period of restriction except as described in the immediately following sentence. If a projected period of restriction exceeds 2 months' duration, Pasadena may make other arrangements for energy for the remainder of such Contract Year if Pasadena has entered into a contractual commitment with a third party as a direct result of Bonneville's prior notice of restriction, and Bonneville has received Pasadena's written notice of such arrangements not later than 10 days prior to the projected end of such period of restriction.

During any period that Bonneville continues to have surplus firm energy on a planning basis, but Bonneville restricts the delivery of

energy as provided above, Bonneville shall make available capacity at the Contract Demand and, in the event of a partial energy restriction, a pro rata amount of energy. Prior to the effective date of the restriction, Pasadena shall give notice to Bonneville of the amount of capacity made available by Bonneville that Pasadena desires for the anticipated duration of the restriction. In such notice, Pasadena may reduce the amount of capacity it desires for the anticipated period of restriction below the Contract Demand, with no change in the rate per kW-mo. of capacity specified in section 9; provided, however, that if Pasadena reduces the amount of capacity it desires during a period of restriction to zero, and the reduction to zero capacity occurs on any day other than the last day of a month, then Bonneville shall make a pro rata reduction in the rate per kW-mo. of capacity. Terms for the delivery of such capacity and for the cash-out or delivery of Peaking Replacement Energy shall be as provided in this Agreement.

13. Points of Delivery.

13(a) Points of Delivery.

The point of delivery for all deliveries pursuant to this Agreement is NOB.

13(b) Other Pacific Southwest Points of Delivery.

Notwithstanding the point of delivery specified in subsection 13(a), at Bonneville's request, Pasadena shall

deliver energy owed Bonneville to Pacific Southwest points of delivery where Pasadena has interconnections and available transmission capacity with Pacific Southwest utilities.

13(c) Costs Incurred to Point of Delivery.

Each Party shall bear its own costs for deliveries to the point of delivery under subsections 13(a) and 13(b); provided, however, that all deliveries of Supplemental Energy by Pasadena to Bonneville pursuant to subsection 7(c) shall be excluded from the provisions of this subsection.

14. Limit of Liability.

It is mutually understood and agreed that Pasadena's obligations for the payment of monies pursuant to this Agreement are limited to revenues received by Pasadena from the sale of electric power and/or the disposition of assets of Pasadena's power generation and transmission facilities.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By/S/ JAKMES J. JURA
Administrator

Date January 28, 1988

CITY OF PASADENA, CALIFORNIA

By/S/ EARL K. AHGAJANI

Title Deputy City Manager

Date 1/06/88

PLAN OF DELIVERY

1. Monthly Amounts of Energy Requested by Pasadena Pursuant to Subsection 5(e).

Year / Month	1988	1989	1990	1991
July				
August				
September				
October				
November				
December				
January				
February				
March				
April				
May				
June				

This attachment will be revised each year upon Pasadena's submission of new data.

2. Example, assuming 1992 Power Sale.

Upon Pasadena's submittal of plans of delivery each year in accordance with subsection 5(e), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations. Assuming energy sufficient to serve Pasadena load as a power sale, the plan of delivery to be used is based upon the degree to which the coordinated system refills.

At 2400 hours on July 31, 1992, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will implement the most recent plan of delivery submitted by Pasadena. If the system does not refill, such parties will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier "Critical Periods"). This can be shown as follows:

Critical Period	Pasadena's Plan of Delivery
1992 - 1995 (refill)	year 1992 from 1992 submittal
1991 - 1994	year 1992 from 1991 submittal
1990 - 1993	year 1992 from 1990 submittal
1989 - 1992	year 1992 from 1989 submittal

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

Contract No. DE-MS79-87BP92413
City of Pasadena
Effective at 2400 hours January 31, 1988

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR PASADENA

	BLOCK 1: 6 MW DEMAND			BLOCK 2: 6 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	19%	= 848					848
F	19%	= 766					766
M	25%	= 1,116					1,116
A	32%	= 1,382					1,382
M	35%	= 1,562	May (15-31)	30%	= 734		2,296
J	35%	= 1,512		30%	= 1,296		2,808
J	41%	= 1,830		30%	= 1,339		3,169
A	41%	= 1,830		33%	= 1,473		3,303 1/
S	41%	= 1,771		30%	= 1,296		3,067
O	32%	= 1,328	Oct. (1-14)	9%	= 181		1,609
N	19%	= 821					821
D	19%	= 848					848
TOTAL		15,714			6,319		
TAKE-OR-PAY		18,396 2/			6,610 2/		
BLOCK 1 LF = 35%				BLOCK 2 LF = 30%			

1/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

2/ These figures will be increased on July 1, 1992, pursuant to page 2 of this Exhibit D.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR PASADENA

	BLOCK 1: 6 MW DEMAND			BLOCK 1: 6 MW DEMAND			BLOCK 2: TOTAL MWh
	LF	=	MIN. MWh	LF	=	MIN. MWh	
J	20%	=	893				893
F	20%	=	806				806
M	27%	=	1,205				1,205
A	33%	=	1,426				1,426
M	37%	=	1,652 (May 15-31)	32%	=	783	2,435
J	37%	=	1,598	32%	=	1,382	2,980
J	43%	=	1,920	32%	=	1,428	3,348
A	43%	=	1,920	35%	=	1,562	3,482 1/
S	43%	=	1,858	32%	=	1,382	3,240
O	33%	=	1,473 (Oct. 1-14)	10%	=	202	1,675
N	20%	=	864				864
D	20%	=	893				893
TOTAL			16,508			6,739	
TAKE-OR-PAY			21,024			7,711	

BLOCK 1 LF = 40%

BLOCK 2 LF = 35%

1/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

OPERATING PROCEDURES

No operating procedures have been established as of the date of execution of this Agreement.

Prior to conversion to the Exchange, the Parties agree to develop operating procedures which shall be utilized during the Exchange. Such procedures shall include, but are not limited to, determination and verification of Total Incremental Cost, determination and verification of UIC, operating procedures under the Energy Account, and operating procedures during periods of Total Outage and Partial Outage.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in this Agreement.

(WP-PKLD-3462c)

Contract No. DE-MS79-90BP92858

4/9/90

FIRM PEAKING CAPACITY SALE/EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

RIVERSIDE, CALIFORNIA

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Exhibit A (Wholesale Power Rate Schedules and General
General Rate Schedule Provisions) .....
Exhibit B (Bonneville General Contract Provisions Form PSC (SW-1)) ....
Exhibit C (16 U.S.C. Section 837 (1984) Public Law 88-552) .....

Bonneville-Riverside

Firm Peaking Capacity Sale/Exchange Agreement

This FIRM PEAKING CAPACITY SALE/EXCHANGE AGREEMENT (Agreement) is executed as of June 15, 1990, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville"), and the CITY OF RIVERSIDE, CALIFORNIA ("Riverside"), a municipal corporation of the State of California. Bonneville and Riverside hereinafter sometimes are referred to individually as "Party" and collectively as "Parties".

WITNESSETH

WHEREAS Bonneville sells electric capacity at wholesale, and projects availability of amounts in excess of its existing obligations to deliver such capacity to its Pacific Northwest customers; and

WHEREAS Riverside is the owner of an electric generation, transmission and distribution system which it uses to supply electric energy to its customers and other utilities; and

WHEREAS Riverside has obtained or intends to obtain transmission service between the Nevada-Oregon border and Sylmar Substation on the DC Intertie (DC Intertie Transmission Service Agreement); and

WHEREAS Riverside and the Southern California Edison Company (SCE) have entered or intend to enter into an agreement which provides for SCE to transmit electric power and energy acquired pursuant to this Agreement between the Sylmar Substation and the point where the electrical facilities of Riverside and SCE interconnect (SCE-Riverside Sylmar Firm Transmission Service Agreement); and

WHEREAS Riverside desires to (i) exchange capacity obtained from Bonneville during the Summer Season for energy returned to Bonneville during the Delivery Season and (ii) purchase capacity from Bonneville during the Winter Season, using the transmission capacity obtained under the DC Intertie Transmission Service Agreement and the SCE-Riverside Sylmar Firm Transmission Service Agreement under the terms specified herein; and

WHEREAS Bonneville is authorized pursuant to law to dispose of surplus electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority.

NOW, THEREFORE, the Parties hereto agree as follows:

1. Effective Date and Term.

(a) Effective Date.

Unless otherwise agreed, this Agreement shall become effective at 0001 hours on the first day of the first month after the occurrence of all the following events (Effective Date).

(1) Execution of this Agreement by both Parties; and

(2) Execution and acceptance for filing by the FERC, of the SCE-Riverside Supplemental Integration Agreement between SCE and Riverside; and

(3) Execution and acceptance for filing by the FERC, of the SCE-Riverside Sylmar Firm Transmission Service Agreement; and

(4) Execution of the DC Intertie Transmission Service Agreement(s).

(b) Term.

This Agreement shall remain in full force and effect until the earlier of (i) twenty (20) years from the Effective Date; or (ii) the date the SCE-Riverside Sylmar Firm Transmission Service Agreement terminates; or (iii) the date the DC Intertie Transmission Service Agreement(s) terminate(s), unless replaced by other agreements or other suitable arrangements. All obligations incurred hereunder prior to termination shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified.

(a) "Calendar Week" means the week beginning at 0001 hours on Sunday and ending at 2400 hours on the following Saturday.

(b) "Contract Demand" means the maximum hourly rate of delivery for Firm Peaking Capacity and associated Firm Peaking Energy, determined pursuant to sections 4(a) and 5(a).

(c) "Delivery Season" means the period beginning at 0001 hours on October 1 and ending at 2400 hours on the following April 15, unless extended by Bonneville pursuant to section 7(b)(2).

(d) "DC Intertie" means that portion of the direct-current 1000 kilovolt extra high voltage electric transmission line between California and the Pacific Northwest.

(e) "Energy Account" means an account consisting of monthly totals of Exchange Energy and Peaking Replacement Energy, the delivery of which Bonneville has deferred pursuant to sections 4(c) and 6(b), or energy not rescheduled pursuant to the provisions section 8(c).

(f) "Exchange Energy" means the energy Riverside is obligated to deliver to Bonneville during a Delivery Season in exchange for Bonneville deliveries of Firm Peaking Capacity the preceding June 1 to October 31.

(g) "FERC" means The Federal Energy Regulatory Commission, or its successor.

(h) "Firm Peaking Capacity" means the capacity delivered by Bonneville to Riverside pursuant to this Agreement.

(i) "Firm Peaking Energy" means the energy associated with Bonneville's deliveries of Firm Peaking Capacity.

(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission rights under the DC Intertie Transmission Service Agreement(s) due to physical or operating limitations, or (ii) a complete interruption of deliveries due to a reduction of available DC Intertie transmission rights under the DC Intertie Transmission Service Agreement(s) due to physical or operating limitations, for a period of time which is less than twenty-four (24) consecutive hours.

(k) "Peaking Replacement Energy" means the energy which Riverside is obligated to deliver to Bonneville, pursuant to section 6, to replace Firm Peaking Energy supplied by Bonneville.

(l) "Point of Delivery" means the point(s) where deliveries of electric power and energy between the Parties takes place pursuant to section 9.

(m) "SCE-Riverside Supplemental Integration Agreement" means the agreement executed between SCE and Riverside for the integration of capacity and energy acquired pursuant to this Agreement.

(n) "Summer Season" means the period beginning at 0001 hours on June 1 and ending at 2400 hours on the following October 31.

(o) "Total Incremental Cost" means the sum of the incremental fuel cost, incremental operation and maintenance cost, generating unit start-up cost, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Riverside in supplying Exchange Energy to Bonneville, including transmission losses incurred by Riverside in delivering Exchange Energy to the Point of Delivery, that would not otherwise have been incurred.

(p) "Total Outage" means the complete interruption of deliveries due to a reduction of available DC Intertie transmission rights under the DC Intertie Transmission Service Agreement(s), for a period of time which equals or exceeds twenty-four (24) consecutive hours.

(q) "Uncontrollable Force" means any act or event beyond the control of a Party which adversely affects the ability of the Party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid, including, but not

limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning, and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage, and restraint by court order or by regulatory authorities; and, after a good faith effort by the appropriate Party to so obtain, action or nonaction by or failure to obtain the necessary authorizations or approvals from any governmental agency or regulatory authority.

(r) "Winter Season" means the period beginning at 0001 hours on November 1 and ending at 2400 hours on the following May 31.

(s) "Workday" means each day which both Bonneville and Riverside observe as a regular day of work.

3. Exhibits.

Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), Bonneville's General Contract Provisions (Form PSC (SW-1)) (Exhibit B), and 16 U.S.C. Section 837 (1984) (Public Law 88-552) (Exhibit C), are attached hereto and hereby made a part of this Agreement. In the event a provision of Exhibit A or B conflicts with sections 1 through 20 of this Agreement, then the provisions of sections 1 through 20 of this Agreement shall control. In the event a provision in Exhibit B conflicts with a provision of Exhibit A, then the provision in Exhibit A shall control.

4. Capacity for Energy Exchange.

(a) Firm Peaking Capacity and Energy.

(1) During the Summer Season, the Contract Demand shall be twenty-three (23) megawatts (MW).

(2) Bonneville shall make available to Riverside Firm Peaking Capacity each hour in an amount equal to the Contract Demand. Firm Peaking Energy shall be delivered pursuant to the scheduling provisions of section 11, in daily amounts, including holidays, up to ten (10) megawatthours (MWH) per MW of Contract Demand, and in Calendar Week amounts up to fifty (50) MWH per MW of Contract Demand.

(b) Exchange Energy.

(1) Riverside shall, in return for Firm Peaking Capacity made available by Bonneville the preceding June 1 to October 31, deliver Exchange Energy to Bonneville each Delivery Season as provided herein. The amount of such energy provided each Delivery Season shall equal the exchange ratio in MWH/MW multiplied by the Contract Demand in MW for such capacity. The exchange ratio shall be twelve hundred (1200) MWH/MW.

(2) Unless otherwise agreed, except as provided in section 4(c), Exchange Energy shall be delivered in October during weekend hours to the extent the Parties anticipate such deliveries are required to meet Riverside's Exchange Energy obligation during that Delivery Season. The remaining balance of Exchange Energy shall be delivered in equal weekly increments during the period of November 1 through April 15, unless otherwise agreed by the Parties.

(3) Except as provided in section 8, if Bonneville makes Firm Peaking Capacity available for less than a full Summer Season, the amount of Exchange Energy which Riverside is obligated to deliver to Bonneville shall be reduced proportionately to account for the partial deliveries of Firm Peaking Capacity.

(c) Exchange Energy Delivery Limitations.

(1) Unless otherwise agreed the maximum hourly rate of delivery for Exchange Energy shall be 100 percent of the Contract Demand set forth in section 4(a)(1). Upon agreement of the Parties' schedulers, and subject to Riverside making arrangements for additional intertie capacity or counter-scheduling against a Bonneville delivery to Riverside: (i) during the months of October, November, December, January, and February, the maximum hourly rate of delivery for Exchange Energy shall be 200 percent of the Contract Demand set forth in section 4(a)(1); and (ii) during the months of March and April, the maximum hourly rate of delivery for Exchange Energy shall be 130 percent of the Contract Demand set forth in section 4(a)(1); provided, however that such maximum hourly rates of delivery shall be reduced by an amount equal to the amount of Peaking Replacement Energy concurrently being delivered pursuant to section 6.

(2) Subject to Partial Outages and Total Outages, and unless limited by Bonneville pursuant to sections 4(c)(3) and 4(c)(4), Riverside shall complete each Calendar Week's obligation to deliver Exchange Energy by the end of such Calendar Week.

(3) At the time schedules for the delivery of Exchange Energy are established by Riverside pursuant to section 11, Bonneville may limit the delivery rate for Exchange Energy to not less than sixty (60) percent of the then applicable Contract Demand.

(4) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Exchange Energy, including down to zero (0).

(5) To the extent that Bonneville restricts the delivery of Exchange Energy, Bonneville may (i) place such energy into the Energy Account as described in section 7; or (ii) the Parties may mutually agree to delay the delivery of such energy.

5. Firm Peaking Capacity Sale.

(a) Firm Peaking Capacity and Energy.

(1) During the Winter Season, the Contract Demand shall be sixteen (16) MW for the months of November through April and twenty-three (23) MW for the month of May.

(2) Bonneville shall make available to Riverside and Riverside shall purchase Firm Peaking Capacity each hour in an amount equal to the Contract Demand. Firm Peaking Energy shall be delivered pursuant to the scheduling provisions of section 11, in daily amounts, including holidays, up to ten (10) MWH per MW of Contract Demand, and in Calendar Week amounts up to fifty (50) MWH per MW of Contract Demand.

(3) Except as provided in section 8, if Bonneville makes Firm Peaking Capacity available for less than a full month, the demand charge shall be reduced pro-rata,

(b) Demand Charge.

The demand charge for Firm Peaking Capacity made available by Bonneville each November 1 through May 31 and applied to the Contract Demands specified in section 5(a) shall initially be $4.65 per kilowatt-month.

Each October 1, beginning October 1, 1990, the demand charge shall be recalculated as follows and rounded to the nearest cent:

$$SPnew = SPprev * \frac{PFnew}{PFprev} * 1.01$$

Where:

SPnew = The Firm Peaking Capacity demand charge, as adjusted hereunder to become effective each October 1, in dollars per kilowatt-month.

SPprev = The Firm Peaking Capacity demand charge in effect immediately prior to each October 1, in dollars per kilowatt-month.

PFprev = The average Bonneville Priority Firm (PF) rate, or successor rate(s) thereto, in effect the previous October 1, in mills per kilowatthour (kWh). Such average PF rate, and any successor rate(s), shall be calculated to the nearest hundredth of a mill at a load factor of fifty (50) percent, and assuming a uniform demand in each month. If there is more than one PF rate,

or successor rate(s), the average shall be determined by a weighting based on forecasted sales in the relevant rate case.

PFnew = The average PF rate, or successor rate(s) thereto, in effect on each October 1 contract rate adjustment date, in mills per kWh. Such average PF rate, and any successor rate(s), shall be calculated to the nearest hundredth of a mill at a load factor of fifty (50) percent, and assuming a uniform demand in the each month. If there is more than one PF rate, or successor rate(s), the average shall be determined by a weighting based on forecasted sales in the relevant rate case.

6. Peaking Replacement Energy.

(a) Obligation to Deliver.

Subject to section 8(b), Riverside shall be obligated to return Peaking Replacement Energy to Bonneville equal to the amounts of Firm Peaking Energy previously delivered to Riverside by 2400 hours on the day following Bonneville's prior Firm Peaking Energy delivery.

(b) Peaking Replacement Delivery Limitations.

(1) Unless otherwise agreed, the maximum hourly rate of delivery of Peaking Replacement Energy shall be one hundred (100) percent of the Contract Demand specified in section 4(a)(1).

(2) At the time schedules for the delivery of Peaking Replacement Energy are established by Riverside pursuant to section 11, Bonneville may limit the delivery rate for Peaking Replacement Energy to not less than sixty (60) percent of the then applicable Contract Demand.

(3) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Peaking Replacement Energy, including down to zero (0).

(4) To the extent that Bonneville restricts the delivery of Peaking Replacement Energy, Bonneville may (i) place such energy into the Energy Account as described in section 7; or (ii) the Parties may agree to delay the delivery of such energy.

7. Energy Account.

(a) Bonneville shall maintain the Energy Account. The Energy Account shall contain monthly amounts of Peaking Replacement Energy and Exchange Energy which has not been delivered to Bonneville due to either limitations by Bonneville pursuant to sections 4(c) and 6(b) or transmission limitations pursuant to section 8(c).

(b) Subject to section 7(b)(1), Bonneville may withdraw energy from the Energy Account during a Calendar Week by providing Riverside with notice by 1400 hours on the Thursday prior to such Calendar Week, specifying the weekly quantity of energy to be withdrawn, and the rate(s) of delivery for such energy. Unless otherwise mutually agreed, the rate(s) of delivery shall not exceed the

then applicable Contract Demand and the times of delivery shall be those hours other than (i) 0800 to 2200 hours Monday through Friday, excluding holidays, during the period November 1 through April 30; and (ii) 0900 to 2300 hours Monday through Friday, excluding holidays, during the period May 1 through October 31. Energy withdrawn from the Energy Account shall be withdrawn on a first-in-first-out basis.

(1) Unless otherwise agreed, Bonneville may not withdraw more than 1800 MWH from the Energy Account in any Calendar Week. Such withdrawals shall not cause Riverside to defer or otherwise limit deliveries of Firm Peaking Capacity, Firm Peaking Energy, Exchange Energy or Peaking Replacement Energy. Riverside shall deliver energy as requested pursuant to section 7(b) during the Delivery Season from the Energy Account, subject to forced outages. Except as provided in sections 7(b)(2) and 7(b)(3), withdrawals from the Energy Account at times other than during the Delivery Season shall be by agreement of the Parties' schedulers.

(2) Bonneville at its option, may extend the Delivery Season to April 30 and, subject to the provisions of this section 7, schedule energy from the Energy Account during the appropriate light load hours specified in this section 7(b). Any remaining balance in the Energy Account will be delivered pursuant to the provisions of this section 7, or cashed out pursuant to section 7(c).

(3) After April 30, and at Bonneville's request, the Parties shall attempt in good faith to develop a mutually agreeable plan for the delivery of any energy remaining in the Energy Account pursuant to section 8(c). If the Parties are unable to agree on a plan, and such energy is not delivered

by July 31, the energy shall be cashed out at the rate specified in section 7(c).

(c) Each August 1, energy remaining in the Energy Account shall be cashed out at the cash-out price in effect at the time such energy was entered into the Energy Account. The cash-out price for such energy is Bonneville's average cost of nonfirm energy, as calculated in Bonneville's rate cases. Riverside shall be relieved of any obligation to provide energy to Bonneville to the extent the energy is cashed out.

8. Transmission Limitations.

(a) In the event of an interruption of deliveries by either Party due to a Total Outage or a Partial Outage, transactions under this Agreement will have priority over (i) any competing nonfirm energy transaction of Riverside and Bonneville and (ii) any firm transactions providing for a capacity sale or a capacity for energy exchange under agreements executed after the date of execution of this Agreement.

(b) Following periods of Partial Outage or Total Outage, Riverside shall continue to be obligated to deliver Peaking Replacement Energy and Exchange Energy. Both Parties shall use best efforts to reschedule interrupted or curtailed deliveries of Peaking Replacement Energy and Exchange Energy under conditions approximately equivalent to the conditions existing prior to the Partial Outage or Total Outage; provided, that in rescheduling Peaking Replacement Energy and Exchange Energy, Riverside shall not exceed the delivery limits set forth in sections 4(c) and 6(b), unless otherwise agreed. The Parties may also agree to reschedule delivery at other times and under conditions other than those existing prior to the Partial Outage or Total Outage.

(c) Peaking Replacement Energy and Exchange Energy shall be rescheduled within sixty (60) days following the end of the Partial Outage or Total Outage, unless the Parties otherwise mutually agree. To the extent the Parties have not so rescheduled such energy, the Energy Account shall be credited for any such amounts of Peaking Replacement Energy and Exchange Energy, with an effective date of the first day after the end of the Partial Outage or Total Outage.

(d) Exchange Energy Relief.

(1) In the event that (i) there has been more than three hundred (300) hours of Total Outages during the Summer Season; and (ii) Bonneville has elected not to purchase Exchange Energy pursuant to section 8(f); and (iii) deliveries of Firm Peaking Energy, which the Parties reasonably expect would have been delivered but for the occurrence of Total Outages in excess of three hundred (300) hours, have not been rescheduled, then Riverside shall be excused from delivering a proportional amount of Exchange Energy determined pursuant to section 8(d)(2). For any partial Summer Season deliveries of Firm Peaking Capacity hereunder, a pro-rated sum of Total Outages based on three hundred (300) hours shall be used.

(2) A ratio shall be calculated, the numerator shall be the number of hours of Total Outages in the Summer Season exceeding three hundred (300), and the denominator shall be the number of hours in the Summer Season. This ratio shall then be multiplied by the exchange ratio and the resultant product subtracted from the exchange ratio to determine the amount of Exchange Energy which Riverside shall be obligated to deliver to Bonneville.

(e) Firm Peaking Capacity Sale Relief.

(1) In the event that (i) there has been more than four hundred twenty hours (420) hours of Total Outages during the Winter Season; and (ii) deliveries of Firm Peaking Energy, which the Parties reasonably expect would have been delivered but for the occurrence of Total Outages in excess of four hundred twenty (420) hours, have not been rescheduled, then Riverside shall receive a capacity payment credit determined pursuant to section 8(e)(2). For any partial Winter Season sale hereunder, a pro-rated sum of Total Outages based on the four hundred twenty (420) hours shall be used,

(2) For each Total Outage, following the occurrence of a relief condition described in section 8(e)(1), Riverside shall receive a capacity payment credit for the duration of such Total Outage. The capacity payment credit shall be calculated by determining the duration of such Total Outage during the billing month, divided by the total number of hours in that month. The resultant factor shall be multiplied by the demand charge per kilowatt-month, multiplied by the applicable Contract Demand for the month to determine the capacity payment credit.

(f) Bonneville Purchase of Exchange Energy.

Bonneville may elect to purchase Exchange Energy which Riverside otherwise would be excused from delivering pursuant to section 8(d) as follows:

(1) Bonneville shall notify Riverside at least one (1) month prior to requesting delivery of such Exchange Energy.

(2) Within ten (10) Workdays after receipt of Bonneville's notice requesting Exchange Energy, and prior to Riverside committing to obtain Exchange Energy, Riverside shall inform Bonneville of the probable lowest cost resources available to supply such requested Exchange Energy, including the estimated Total Incremental Cost of such resources. Riverside shall revise the Total Incremental Cost if conditions change substantially.

(3) Bonneville shall provide Riverside with at least one (1) Calendar Week's final written notice prior to the start of each Calendar Week's deliveries whether Bonneville shall require Riverside to deliver the Exchange Energy, or whether Bonneville relieves Riverside of the obligation to deliver that Calendar Week's Exchange Energy.

(4) For all deliveries of Exchange Energy pursuant to this section 8(f), Bonneville shall pay Riverside the Total Incremental Cost of the Exchange Energy for the first three (3) months of deliveries, and one hundred fifteen (115) percent of Riverside's Total Incremental Cost for all Exchange Energy delivered after three (3) months pursuant to this section 8(f).

9. Points of Delivery.

Deliveries shall be at the point where the DC Intertie crosses the Nevada-Oregon border, or the point(s) where the 500 kV alternating current transmission line(s) between Oregon and California cross the California-Oregon border, or at such other points as agreed by the Parties.

10. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of Public Law 88-552 (the Northwest Preference Act) and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to Public Law 88-552, Bonneville shall have the right to restrict or terminate delivery of all or a portion of the capacity associated with the Firm Peaking Capacity sale on five (5) years written notice specifying the amounts and duration of the restriction, if such capacity is needed to meet the capacity requirements in the Pacific Northwest (as defined in Public Law 88-552). Such restrictions to Riverside shall be limited to the amounts and duration necessary to cover Bonneville's projected Pacific Northwest needs. The sale of capacity to Riverside under this Agreement shall continue in months during which such capacity is not needed, as determined by Bonneville, in the Pacific Northwest.

11. Scheduling Provisions.

Submission of all schedules between Bonneville and Riverside, or its agent, for delivery of capacity and energy hereunder shall be subject to the following provisions unless otherwise agreed by the Parties' schedulers or dispatchers, or their agents as designated by a Party to act on its behalf:

(a) Preschedules shall be completed by 0930 hours on each Workday and shall be effective for each hour of the following day, or days, through the next Workday.

(b) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts of Firm Peaking Energy that Riverside, or its agent, anticipates it will schedule from Bonneville each day for the following ten (10) days. Riverside, or its agent, shall

submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Riverside, or its agent, or Bonneville to schedule such amounts.

(c) Each Party, or its agent shall endeavor to avoid requesting changes in schedules. While changes in preschedules may be permitted in certain circumstances, requests for such changes in prescheduled amounts for any hour shall be only as agreed. Normally such changes shall be submitted no later than thirty (30) minutes before the hour for which the change is to be effective.

12. Payment.

(a) Riverside agrees to pay Bonneville in accordance with this Agreement upon receipt of bills sent by Bonneville. Bonneville shall render preliminary and final adjusted monthly bills to Riverside. Riverside shall pay Bonneville by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday, as observed by Riverside, then the due date shall be the next following business day. Payment of bills shall be in accordance with Exhibits A and B, attached hereto.

(b) Bonneville may offset any amount due Riverside pursuant to this Agreement by any amount due to Bonneville pursuant to both this Agreement and any other agreement between the Parties. Riverside may offset any amount due Bonneville pursuant to this Agreement by any amount due to Riverside pursuant to both this Agreement and any other agreement between the Parties. Such net billing shall accomplish timely payment.

13. Uncontrollable Forces.

(a) Obligations of the Parties, other than those to pay money under section 12, shall be excused when failure to perform such obligations is due to an Uncontrollable Force; provided, however, that the Parties shall seek remedies as set forth in section 16; and provided further, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability with reasonable dispatch. Nothing in this section 13 shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(b) Each Party shall notify the other as soon as possible of any Uncontrollable Force which may adversely affect performance under this Agreement. Failure of a Party to give notice to the other Party shall not be deemed a waiver of such Uncontrollable Force.

(c) If an Uncontrollable Force causes a Partial Outage or Total Outage, this section 13 shall not apply until one (1) Year after the commencement of the Partial Outage or Total Outage.

14. Assignment of Agreement.

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

15. Notices.

Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given, or made if delivered in person or sent by telegraph, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:

To Riverside: Public Utilities Director
City of Riverside
3900 Main Street
Riverside, CA 92522

To Bonneville: The Administrator
United States Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Either Party may, by written notice to the other Party, change the designations or address of the person so specified as the one to receive notices pursuant to this Agreement.

16. Disputes.

Pending resolution of the disputed matter, the Parties shall continue performance of their respective obligations pursuant to this Agreement. The Parties shall discuss disputes regarding any matter relating to this Agreement, and shall use their best efforts to amicably and promptly resolve each such dispute.

17. Audits.

Each Party shall reserve the right to audit and to examine any cost, payment, settlement or supporting documentation, including, but not limited to, audit reports, resulting from any items set forth in this Agreement. Any such Audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The Party being audited agrees to cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of five (5) years following the first billing for such cost under this Agreement. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period.

The Party being audited shall be notified in writing of any exception taken as a result of an audit promptly after completion of the audit. The Party being audited shall have thirty (30) days to review the notice of exception.

(a) If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) to the other Party, with interest calculated in the same manner as in Exhibits A and B, or their successors, within ten (10) days after agreement is reached.

(b) If the Parties dispute any exception(s) taken as a result of the audit, the owing Party shall so notify the other Party in writing promptly after its receipt of the written notification of exception. Such dispute shall then be subject to the provisions set forth in section 16. If upon resolution of the dispute, it is determined that a Party shall make payment to the other Party, such payment shall be made within ten (10) days of resolution of the dispute, with interest calculated in the same manner as set forth in Exhibits A and B, or their successors.

18. Governing Law.

This Agreement shall be interpreted, governed by and construed under Federal law applicable to Bonneville.

19. Waivers.

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement shall be waived except in writing. Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or with any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter.

20. Signature Clause.

The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Assistant Administrator

Date JUN 15 1990

CITY OF RIVERSIDE

By _____

Title Mayor

Date APR 27 1990

ATTEST:

By _____

Title City Clerk

Date APR 27 1990

APPROVED AS TO FORM
_____ 4/27
ASST. CITY ATTORNEY

(VS6-PMCE-4321c)

EXHIBIT A

1989 Wholesale Power Rate Schedules

and General Rate Schedule Provisions

Bonneville
POWER ADMINISTRATION

United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, Oregon 97232

Bonneville Power Administration's 1989 Wholesale Power Rate Schedules and General Rate Schedule Provisions, contained herein, were approved on an interim basis effective October 1, 1989. These rate schedules and provisions were approved by the Federal Energy Regulatory Commission, United States Department of Energy, in a Commission Order issued September 29, 1989 (Docket No. EF89-2011-000).

These rate schedules and provisions supersede in their entirety the Administration's Wholesale Power Rate Schedules and General Rate Schedule Provisions effective July 1, 1987.

WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

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SCHEDULE PF-89

PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, construction, test and start-up, and station service.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, Bonneville Power Administration (BPA) may make power available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule PF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule includes the Preference rate and the Exchange rate. The Preference rate is available for the general requirements of public body, cooperative and Federal agency customers and includes credit attributed to the provision of section 7(b)(2) of the Northwest Power Act. The Exchange rate is available for all purchases of residential and small farm exchange power pursuant to the Residential Purchase and Sale Agreements.

A. Preference Rate

1. Demand Charge

a. $3.46 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 18.4 mills per kilowatthour of billing energy for the billing months September through March;

b. 14.4 mills per kilowatthour of billing energy for the billing months April through August.

B. Exchange Rate

1. Demand Charge

a. $3.56 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 19.1 mills per kilowatthour of billing energy for the billing months September through March;

b. 15.1 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

In this section, billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), and metered requirements purchasers and those Priority Firm Power purchasers not covered by sections III.A and III.B (section III.C).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or

(2) the Measured Demand, before adjustment for power factor.

b. the lower of:

(1) the Computed Peak Requirement, or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 78 percent of the Measured Energy (excluding unauthorized increase), and

(2) 22 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 57 percent of the Measured Energy (excluding unauthorized increase), and

(2) 43 percent of the Computed Energy Maximum.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy

The billing energy shall be the energy associated with the utility's residential load for each billing period. Residential load shall be computed in accordance with the provisions of the purchaser's Residential Purchase and Sale Agreement.

C. Metered Requirements Purchasers, Other Purchasers Not Covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking or exchanging power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)

BPA shall apply a discount to the charges for all Priority Firm Power sold to purchasers who are eligible for an LDD. Eligibility for the LDD and the amount of the discount (3, 5, or 7 percent) shall be determined pursuant to section III.C.3 of the GRSPs.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Northwest Power Planning Council has recommended that a conservation surcharge be imposed on those customers subject to such surcharge as determined by the Administrator in accordance with BPA's Policy to Implement the Council-Recommended Conservation Surcharge. The Conservation Surcharge shall be applied pursuant to section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in sections II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the PF rates due to the Cost Recovery Adjustment Clause.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for

those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Priority Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

G. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of Priority Firm Power taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an unauthorized increase. BPA first shall determine the amount of unauthorized increase related to demand and shall treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, which exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

(1) to a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month which exceeds the amount of energy which the purchaser is contractually entitled to take during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

H. Coincidental Billing Adjustment

Purchasers of Priority Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

I. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the power sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's computed peak requirement and computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October;

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PF-89 rate is 78.5 percent FBS and 21.5 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE IP-89

INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for both the contract purchase of Industrial Firm Power and the purchase of Auxiliary Power if requested by the DSI customer and made available by BPA. If a DSI customer purchasing power under this rate schedule requests and BPA makes available power under another applicable wholesale rate schedule the IP-89 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The following rates shall be applied when first quartile service is provided under this rate schedule in accordance with the terms of a purchaser's Power Sales Contract dated August 25, 1981. A separate billing adjustment for the reserves provided by the purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the demand and energy charges.

Any contractual reference to the IP Premium Rate shall be deemed to refer to the demand and energy charges set forth below. Any reference to the IP Standard Rate shall be deemed to refer to the same demand and energy charges minus the Discount for Quality of Service.

A. Demand Charge

1. $4.14 per kilowatt of billing demand occurring during all Peak Period hours.
2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 19.5 mills per kilowatthour of billing energy for the billing months September through March;
2. 15.6 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

A. Billing Demand

The billing demand shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs). If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP-89 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C.3 of the GRSPs.

B. Billing Energy

The billing energy shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

However, if BPA has agreed to serve only a portion of the DSI's load under the IP rate schedule, the billing energy for the power purchased under the IP rate shall be specified in the contract initiating such arrangement.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Discount for Quality of First Quartile Service

1. Application and Amount of First Quartile Discount

If a purchaser requests discounted rate service, a discount of 0.6 mills per kilowatthour of billing energy shall be granted. This billing credit shall be applied to the monthly billing energy under section III.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section IV.D of this rate schedule.

2. Eligibility Requirements for First Quartile Discount

To qualify for the First Quartile Discount the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

B. Curtailments

BPA shall charge the DSI for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract. BPA shall apply the demand charge in effect at the time of the curtailment in the computation of the amount of the curtailment charge. In the event that a purchaser is found to be eligible to have a portion of their load served under an alternative rate schedule, application of the curtailment charge shall be specified in the contract instituting such arrangement.

C. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all power purchases under this rate schedule.

Application of the Cost Recovery Adjustment Clause shall result in a uniform adjustment applied to the demand and energy charges, contained in sections II.A and II.B of this rate schedule, and the first quartile discount, if applicable, contained in section IV.A.1 of this rate schedule.

The uniform percentage (CRAC%) determined in Section III.C.5.c. of the GRSPs shall be applied in the following manner:

$$(1 + \frac{CRAC\%}{100}) * \frac{22.8}{23.5}$$ times the demand, energy, and first quartile discount charges.

where: 22.8 represents the average IP-89 margin-based rate in mills per kilowatthour, and 23.5 represents the average IP-89 floor rate in mills per kilowatthour.

D. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

E. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the IP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE VI-87

VARIABLE INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for purchases under the Power Sales Contract implementing the Variable Industrial Power rate schedule (Variable Rate Contract) of: (1) Industrial Firm Power and (2) Auxiliary Power if requested by the DSI customer and made available by BPA. This schedule is available only for that portion of a DSI's load used in primary aluminum reduction including associated administrative facilities, if any. By virtue of incorporation of this rate schedule and associated General Rate Schedule Provisions (GRSPs) in the Variable Rate Contract, DSIs electing to purchase power under this rate schedule contractually agree to the terms and conditions of this rate schedule. A DSI further agrees to waive for that portion of their load designated to purchase power at the VI rate, all rights they might otherwise have to purchase power at the Industrial Firm Power Rate Schedule for the duration of the Variable Rate Contract. Section VI.J. supplements schedule VI-86. GRSPs effective July 1, 1985, as revised effective August 1, 1986, and as revised in the 1987 rate case and in subsequent wholesale rate filings are applicable to this rate schedule. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. TERM OF THE RATE

This rate schedule shall take effect on August 1, 1986, and shall terminate on midnight June 30, 1993, unless BPA elects to exercise its unilateral option to terminate the rate at midnight June 30, 1991. This termination right is described in section VI.E. of this rate schedule. Actions to invoke an early termination shall comply with section VI.E. of this rate schedule and with the provisions and stipulations set forth in the Variable Rate Contract.

SECTION III. RATE

A. Revised Rate Charges Subject to Rate Case Adjustments

The following rates shall apply to Industrial customers that meet the eligibility requirements and elect to purchase power under the Variable Industrial Power Rate Schedule. These rates shall remain in effect until the next Rate Adjustment Date, at which point the rates shall be adjusted following the procedures set forth in section VI.C. of this rate schedule, unless the Cost Recovery Adjustment Clause triggers, at which point the rates shall be adjusted following the procedures set forth in section VI.J. of this rate schedule. In addition, the Lower Rate Limit also will be subject to a biennial adjustment pursuant to section VI.B. of this rate schedule. The formula to be used in the calculation of the monthly power bill is contained in section IV. A separate billing adjustment for the value of the reserves provided by purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the Plateau Energy Charge.

1. Base Variable Industrial Rate

a. Demand Charge

$5.33 per kilowatt of billing demand occurring during the Peak Period. No demand charge is applied during Offpeak Period hours.

b. Plateau Energy Charge

16.1 mills per kilowatthour of billing energy.

2. First Quartile Service Discount

0.5 mills per kilowatthour of billing energy.

3. Lower Rate Limit

8.3 mills per kilowatthour of billing energy.

4. Upper Rate Limit

21.9 mills per kilowatthour of billing energy.

B. Initial Rate Parameters Subject to Annual Adjustments

The following rate parameters shall be used in determining the power bills for customers electing to purchase power under the Variable Industrial Power rate schedule. These parameters will be adjusted annually starting on July 1, 1987, and every July 1 thereafter, in accordance with the procedures contained in section VII.B. of the GRSPs.

1. Lower Pivot Aluminum Price

60.8 cents per pound.

2. Upper Pivot Aluminum Price

73.4 cents per pound.

SECTION IV. FORMULA

The Variable Industrial Power rate is a formula rate tied to the U.S. market price of aluminum. Under this rate schedule, the monthly energy charge varies in response to changes in the average price of aluminum in U.S. markets.

A. Demand Charge

1. The Demand Charge, as stated in section III.A.1.a. of this rate schedule, remains constant over all aluminum prices. The demand charge is applied to billing demand occurring during all Peak Period hours for all billing months.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. Plateau Energy Charge

When the monthly billing aluminum price (described in section VII.A. of the GRSPs) is between the Lower Pivot Aluminum Price and the Upper Pivot Aluminum Price inclusive (as stated in sections III.B.1. and III.B.2. of this rate schedule), the monthly energy charge shall be the Plateau Energy Charge as stated in section III.A.1.b. of this rate schedule.

2. Reductions to Plateau Energy Charge

When the monthly billing aluminum price is less than the Lower Pivot Aluminum Price, the monthly energy charge shall be the greater of:

a. The Plateau Energy Charge - (LP - MAP) * (LS)

where:

LP = the Lower Pivot Aluminum Price as stated in section III.B.1. of this rate schedule.

MAP = the monthly billing aluminum price in cents per pound determined pursuant to section VII.A. of the GRSPs

LS = lower slope = $\frac{\text{1 mill per kilowatthour}}{\text{1 cent per pound}}$

or

b. the Lower Rate Limit as stated in section III.A.3. of this rate schedule.

3. Increases to Plateau Energy Charge

When the monthly billing aluminum price is greater than the Upper Pivot Aluminum Price, the monthly energy charge shall be the lesser of:

a. The Plateau Energy Charge + (MAP - UP) * (US)

where:

MAP = the monthly billing aluminum price in cents per pound, as determined according to section VII.A. of the GRSPs.

UP = the Upper Pivot Aluminum Price as stated in section III.B.2. of this rate schedule.

US = upper slope = $\frac{\text{0.75 mills per kilowatthour}}{\text{1 cent per pound}}$

or

b. the Upper Rate Limit, as stated in section III.A.4. of this rate schedule.

SECTION V. BILLING FACTORS

A. Billing Demand

1. Billing Demand for Customers Whose Entire BPA Load is Served at the Variable Industrial Power Rate

The billing demand for power purchased shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10. of the GRSPs.

2. Billing Demand for Customers When Only a Portion of Their Total BPA Load is Served at the Variable Rate

The Billing Demand shall be the portion of the BPA Operating Level attributable to the VI rate as determined by the method specified in the Variable Rate Contract.

3. Billing Demand During Periods of Transitional Service

If BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C. of the GRSPs.

B. Billing Energy

The billing energy for power purchased shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

SECTION VI. OTHER ADJUSTMENTS AND SPECIAL PROVISIONS

A. Lower and Upper Pivot Aluminum Prices

Effective July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices set forth in section III.B. of the rate schedule shall be adjusted following the procedures set forth in section VII.B. of the GRSPs. The adjusted Lower and Upper Pivot Aluminum Prices shall supersede the Lower and Upper Pivot Aluminum Prices contained in section III.B. of the rate

schedule. The revised Lower and Upper Pivot Aluminum Prices shall be used for billing purposes and subsequent adjustments to the Lower and Upper Pivot Aluminum Prices.

B. Lower Rate Limit

Beginning with the July 1, 1988, annual adjustment date and every second July 1 thereafter, the Lower Rate Limit as stated in section III.A.3. shall be increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall supersede the Lower Rate Limit as stated in section III.A.3. of the rate schedule. This increase is in addition to rate adjustment increases in the Lower Rate Limit described in section VI.C. of this rate schedule. In the event that a rate adjustment date and the annual adjustment date occur simultaneously, the Lower Rate Limit shall be adjusted first for changes in the Plateau Energy Charge pursuant to section VI.C. of this rate schedule, and then increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall be used for billing purposes and subsequent rate adjustments.

C. Rate Adjustments

The overall rate level of this rate shall be subject to adjustment in BPA's general wholesale power rate case following the procedures and directives of the Northwest Power Act. The overall rate level consists of the Demand Charge, Plateau Energy Charge, and First Quartile Service Adjustment contained in sections III.A.1. and III.A.2.; these shall be adjusted by a uniform percentage based on the percentage change in the overall rate level. The Lower and Upper Rate Limits as stated in sections III.A.3. and III.A.4. of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, in the Plateau Energy Charge. The Lower and Upper Pivot Aluminum Prices shall not be adjusted in the rate case; rather, they shall be adjusted pursuant to the procedures described in section VII.B. of the GRSPs. The lower and upper slopes shall not be adjusted. The rate for unauthorized increase shall be separately determined in each rate case.

D. Discount for Quality of First Quartile Service

If a purchaser requests First Quartile service with other than Surplus FELCC, a discount contained in section III.A.2. of this rate schedule shall be granted. This billing credit shall be applied to the monthly billing energy under section V.B. for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section VI.G. of this rate schedule. To qualify for the First Quartile Discount, the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

E. Termination Provision

The Administrator may terminate the Variable Industrial Power rate effective midnight June 30, 1991, upon a determination that significant changes in the conditions and expectations under which this rate was offered render the continuation of the Variable Industrial rate inconsistent with BPA's stated goals and objectives. BPA shall provide notification of such a determination pursuant to the provisions of the Variable Rate Contract. As part of the notification procedures, BPA shall provide a reasonable opportunity for interested parties to comment on BPA's determination, as well as to examine the comments submitted by other parties, prior to BPA taking final action to cancel the rate. If BPA determines that the Variable Industrial rate will remain in place until midnight June 30, 1993, BPA shall provide notice that so states and no additional action by BPA will be required.

F. Curtailments

BPA shall charge the customer for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract and the provisions contained in the Variable Rate Contract.

G. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

H. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1. of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the BPA Operating Level by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

I. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI

to whom BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2. of the GRSPs.

J. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5. of the GRSPs shall be applied to all power purchases under this rate schedule consistent with the procedures to adjust the Variable Industrial rate and the provisions of the Variable Rate Contract. A uniform adjustment will be made only if it causes demand and Plateau Energy charges and the First Quartile Service Discount to increase.

The uniform percentage (CRAC%) determined in section III.C.5.c. of the GRSPs shall be applied in the following manner:

$(1 + \frac{CRAC\%}{100}) \cdot \frac{22.4}{23.0}$ times the demand and Plateau Energy charges contained in section III.A.1. of this rate schedule and to the First Quartile Service Discount specified in section III.A.2. of this rate schedule.

where: 22.4 represents the average VI-89 margin-based plateau rate in mills per kilowatthour, and 23.0 represents the average VI-89 floor rate in mills per kilowatthour.

The Lower and Upper Rate Limits stated in sections III.A.3. and III.A.4. of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, to the Plateau Energy charge due to application of the Cost Recovery Adjustment Clause. The adjusted rate parameters shall be used for billing purposes and supersede the rate charges subject to the adjustment contained in section III.A. of this rate schedule. The adjusted rate parameters shall also be used in subsequent rate adjustments pursuant to section III.B. of this rate schedule and to subsequent biennial adjustments to the lower rate limit pursuant to section VI.B. of this rate schedule.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the VI-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SI-89

SPECIAL INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available to any DSI purchaser using raw minerals indigenous to the region as its primary resource and qualifying for this special power pursuant to the procedures established in section 7(d)(2) of the Northwest Power Act. This schedule is available for the contract purchase of this special class of industrial power and also for the purchase of Auxiliary Power if requested by the DSI and made available by BPA. The Special Industrial Offpeak rate available for Hanna Nickel Smelting Company pursuant to the Amendatory Agreement executed July 1, 1985, remains in force and is retained herein. Except for the Special Industrial Offpeak rate, schedule SI-89 supersedes schedule SI-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule contains the Standard Special Industrial Power Rate and the Special Industrial Offpeak Rate. The Standard Special Industrial Power Rate is available to any qualifying DSI for full service provided during all hours of the day. The Special Industrial Offpeak Rate is a lower rate available to the Hanna Nickel Smelting Company (Hanna) for service during periods specified by BPA. A separate billing adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power is not contained in the rate schedule; the adjustment is reflected in the Standard Special Industrial Power Rate.

A. Standard Special Industrial Power Rate

1. Demand Charge

a. $3.08 per kilowattmonth of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 16.9 mills per kilowatthour of billing energy for the billing months September through March;

b. 12.9 mills per kilowatthour of billing energy for the billing months April through August.

B. Special Industrial Offpeak Rate

1. Demand Charge

No demand charge in any hour of the day.

2. Energy Charge

7.0 mills per kilowatthour of billing energy during all billing months.

SECTION III. BILLING FACTORS

A. Billing Demand

1. Standard Special Industrial Power Rate

The billing demand for power purchased under the Standard Special Industrial Power Rate shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the Peak Period BPA Operating Levels for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs).

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Special Industrial Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

2. Special Industrial Offpeak Rate

There is no billing demand for purchases under the Special Industrial Offpeak rate.

B. Billing Energy

The billing energy under both the Standard Special Industrial and Special Industrial Offpeak Rates shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

The kilowatthours of billing energy shall be prorated among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE SI-89 RATE FOR THE HANNA NICKEL SMELTING COMPANY

All purchasers, except for Hanna, shall purchase power under the Standard Special Industrial Power rate. Hanna shall have the option to select one of two types of service,

standard service or offpeak service. In this case, BPA will provide standard service under the Standard Special Industrial Power Rate and offpeak service under the Special Industrial Offpeak Rate. Unless BPA receives a formal request from Hanna for service under the Special Industrial Offpeak Rate, all service will be standard service provided under the Standard Special Industrial Power Rate. To change the type of service provided and the associated rate, Hanna shall submit a formal request for service under the preferred rate option in accordance with the terms of the power sales contract providing for purchases under this rate schedule. Once Hanna has elected to purchase under one of the two options, all purchases of Special Industrial Power shall be subject to the terms and conditions of that rate option until such time that Hanna requests the other type of service.

SECTION V. SERVICE UNDER THE SPECIAL INDUSTRIAL OFFPEAK RATE

BPA shall designate the hours during which offpeak service will be available, and shall provide at least 2 weeks' notice before changing those designated hours. BPA shall identify at least 10 and up to 13 hours on each day Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday, during which offpeak service will be available to the purchaser.

If Hanna has elected to be served under the Special Industrial Offpeak Rate, Hanna may request, during the designated offpeak periods, service in an amount not to exceed the purchaser's Contract Demand. During all other hours Hanna shall curtail service to a level not to exceed 15 percent of Contract Demand.

SECTION VI. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Curtailments

BPA shall charge the DSI for curtailments in accordance with the provisions of the DSI's power sales contract. Any curtailment charge levied shall be computed using the Standard Special Industrial Power Rate.

B. Unauthorized Increase Charge

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

If BPA is providing service to Hanna under the Special Industrial Offpeak Rate, the amount by which Hanna's Measured Demand exceeds 15 percent of its Contract Demand during any hour other than the specified special hours shall be considered unauthorized increase.

C. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment for service under the Standard Special Industrial Power Rate, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. For service under the Special Industrial Offpeak Rate, BPA shall increase the billing energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

D. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Special Industrial Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. In addition, no credit shall be applied to purchases under the Special Industrial Offpeak Rate. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

E. Extended Service Provision

The terms of this rate schedule may be extended for a period not to exceed June 30, 1990, in accordance with the Amendatory Agreement effective July 1, 1985, with the Hanna Nickel Smelting Company (Hanna). The Amendatory Agreement contains Hanna's agreement to make certain investments in a wet screening process at its Riddle facility.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SI-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CF-89

FIRM CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of Firm Capacity without energy on a Contract Demand basis. This schedule is available only to those purchasers holding Firm Capacity contracts executed prior to July 1, 1985. It supersedes Schedule CF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

$42.48 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.54 per kilowattmonth of Contract Demand.

SECTION III. BILLING FACTORS

The billing demand shall be the Contract Demand.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the General Rate Schedule Provisions (GRSPs) and subsequent to any other rate adjustments.

B. Extended Peaking Surcharge

The monthly capacity rate specified in section II above shall be increased by the following extended peaking surcharge to compensate BPA for each hour that the purchaser's monthly demand duration exceeds 8 hours:

1. $0.0908 per kilowatt per hour of extended peaking for the months April through October;
2. $0.0512 per kilowatt per hour of extended peaking for the months November through March.

The charge shall be adjusted pro rata for each portion of an hour of extended peaking supplied to the purchaser.

The purchaser's monthly demand duration shall be determined by dividing:

1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the day of maximum kilowatthour use during those hours, provided such day is not a Sunday, by
2. the purchaser's Contract Demand for such month.

The purchaser's extended peaking shall be the amount by which the purchaser's monthly demand duration exceeds 8 hours. The extended peaking surcharge shall not be applied during periods when BPA does not require the delivery of peaking replacement energy by the purchaser.

C. Energy Return Surcharge

The energy associated with the delivery of Firm Capacity must be returned to BPA in accordance with the terms of the purchaser's Firm Capacity Contract. Unless waived by BPA, any purchaser whose energy returns during any single hour exceed 60 percent of the purchaser's Contract Demand during any single hour shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months April through October, and
2. 1.48 mills per kilowatthour for the months November through March.

D. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases under this rate schedule. The percentage increase calculated in sections III.C.5.c of the GRSPs shall be applied to the demand charges contained in section II of this rate schedule.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CF-89 rate is 75.1 percent FBS and 24.9 percent Exchange for contract year service.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CE-89

EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of capacity:

A. when an emergency exists on the purchaser's system, or

B. when the purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser's load, provided the purchaser requests such capacity and BPA has capacity available for such purpose.

This schedule supersedes Schedule CE-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. **Demand Charge**

$1.06 per kilowatt of demand per calendar week or portion thereof.

B. **Intertie Charge**

The demand charge specified above shall be increased by $0.15 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS

The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar week. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, the billing demand for that week shall be the lower demand which BPA is able to supply.

SECTION IV. BILLING PERIOD

Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CE-89 rate is 75.1 percent FBS and 24.9 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NR-89

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers, direct consumption, or use in construction, test and start up, and station service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load. In addition, BPA may make this rate available to those parties participating in exchange agreements that use this rate schedule as the basis for determining the amount or value of power to be exchanged. This schedule supersedes Schedule NR-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $4.13 per kilowatt-month of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 25.5 mills per kilowatthour of billing energy for the billing months September through March;

2. 21.2 mills per kilowatthour of billing energy for the billing months April through August;

SECTION III. BILLING FACTORS

In this section billing factors are listed for computed requirements purchasers (section III.A) metered requirements purchasers, and those purchasers not covered by section III.A. (section III.B.).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this section.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement;

(2) the Measured Demand, before adjustment for power factor; or

b. the lower of:

(1) the Computed Peak Requirement; or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 56 percent of the Measured Energy, and

(2) 44 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 39 percent of the Measured Energy, and

(2) 61 percent of the Computed Energy Maximum.

B. Metered Requirements Purchasers and Other Purchasers Not Covered By Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract. However, purchasers who previously used the Firm Energy rate schedule, FE-2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in section II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the NR rates due to the Cost Recovery Adjustment Clause.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of New Resource Firm Power taking demand and/or energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase. BPA shall first determine the amount of unauthorized increase related to demand and shall then treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, that exceeds the demand which the purchaser is contractually entitled to take during the billing month and that cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy which the purchaser is contractually entitled to take during that month and that cannot be assigned:

(1) to a class of power that BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

F. Coincidental Billing Adjustment

Purchasers of New Resource Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

G. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during the billing month due to an outage on the facilities used by BPA to deliver New Resource Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

H. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the Power Sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's estimated computed peak requirement and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October, and
2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the NR-89 rate is 100.0 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SP-89

SHORT-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Surplus Firm Power for the period ending September 30, 1994, including purchases under the Western Systems Power Pool (WSPP) agreements. BPA is not obligated to make power or energy available under this rate schedule if such power or energy would displace sales under the IP-89, VI-87, PF-89, or NR-89 rate schedules. Schedule SP-89 supersedes schedule SP-87 and associated GRSPs, except in the case of contracts for sales under schedule SP-87 which become effective on or before September 30, 1989. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Contract Rate

1. Demand Charge

a. For contracts that specify 12 months of service per year, $51.48 per kilowatt per year of Contract Demand billed monthly at the rate of $4.29 per kilowatt of Contract Demand occurring during all Peak Period hours in each billing month.

b. For contracts that specify service for fewer than 12 months per year, the monthly demand charge shall be assessed only for the specified service months at the rate of $4.29 per kilowatt of Billing Demand occurring during the Peak Period plus:

$$\frac{\$4.29\ (12 - \text{specified service months})\ .25}{\text{specified service months}}$$

c. No demand charge during Offpeak Period hours

2. Energy Charge

24.3 mills per kilowatthour of Billing Energy.

B. Flexible Rate

Energy charges or demand and energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the purchaser. In no case shall the rate exceed 100 percent of the fixed and variable unit costs of generation and transmission of BPA's highest cost resource including exchange resources. No resource cost determination is needed for sales at less than or equal to the Contract rate.

C. Intertie Charge

Rates in sections II.A and II.B that equal or exceed the Contract rate shall be increased by the following charges for transactions over the Pacific Northwest-Pacific Southwest Intertie.

1. $.36 per kilowatt per month of billing demand and

2. 0.69 mills per kilowatthour of billing energy.

Rates in section II.B having an energy-only charge that equals or exceeds 30.2 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for transactions over the Pacific Northwest-Pacific Southwest Intertie.

SECTION III. BILLING FACTORS

The billing factors shall be the Measured Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for Short-Term Surplus Firm Power on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the SP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE MSL-87

MODIFIED LONG-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is effective December 1, 1988, and is available for the long-term purchase of Surplus Firm Power for use within the Pacific Northwest Region under BPA contracts executed on or before October 1, 1990. This rate schedule shall be offered for an amount of purchases not to exceed 1,350 MW peak and 572 MW average, less long-term purchases of Surplus Firm Power, exclusive of any surplus firm capacity sales, sold under other rate schedules pursuant to contracts executed after July 1, 1988. This rate schedule shall not be available for contracts that obligate BPA to acquire energy resources to support the sale. Sales of surplus firm energy under this rate schedule will not be included as a firm load in BPA's long-term resource planning. For contracts executed on or before October 1, 1990, this rate schedule shall continue in effect for 20 years from the date of execution of such contract, but in no event later than September 30, 2010. This rate schedule shall not be available for contracts executed after October 1, 1990. Schedule SL-87 supersedes schedule FD-85 and associated GRSP's. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The rate for the long-term purchase of Surplus Firm Power shall be mutually agreed to by BPA and the purchaser, provided that the present value of the forecasted revenue under the contract rate, as projected for the contract term at the date of contract execution, shall be equal to or greater than the forecasted revenue under the Floor projection, specified in subsection A below, and less than or equal to the forecasted revenue under the Ceiling projection, specified in subsection B below. The floor and ceiling projections filed with the Federal Energy Regulatory Commission on September 30, 1988, are incorporated by reference in this rate schedule and shall apply to all contracts executed under this rate schedule.

A. Floor Projection

1. Firm Power Sale

The Floor projection shall be the greater of BPA's average Priority Firm rate or BPA's opportunity cost of surplus firm power projected for each year of the contract term. The average PF rate shall be calculated at the load factor of the proposed sale.

2. Firm Capacity Sale

The Floor projection shall be the Priority Firm demand charge projected for each year of the contract term.

3. Combination Firm Power and Firm Capacity Sale

The floor projection shall be the sum of:

a. the floor in section A.1. for each year in which the purchase is a firm power sale; and

b. the floor in section A.2. for each year in which the purchase is a firm capacity sale.

B. Ceiling Projection

1. Firm Power Sale

The ceiling projection shall be the fully-allocated cost of BPA's highest cost resource including transmission costs projected for each year of the contract term.

2. Firm Capacity Sale

The ceiling projection shall be the demand component of BPA's highest cost resource including transmission costs projected for each year of the contract term.

3. Combination Firm Power and Firm Capacity Sale

The ceiling projection shall be the sum of:

a. the ceiling in section B.1. for each year in which the purchase is a firm power sale; and

b. the ceiling in section B.2. for each year in which the purchase is a firm capacity sale.

SECTION III. BILLING FACTORS

The billing factors shall be the Contract Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Escalation Requirement

Adjustments to the contract rate shall occur on the dates specified in the contract but the intervals between adjustment dates shall not exceed five years. Each contract shall include an escalation provision specifying the specific formula and index for escalating the contract rate over the term of the contract as mutually agreed to by the parties. In addition each contract shall specify a minimum escalator based on either changes in BPA's Priority Firm Power rate or changes in BPA's Average System Cost.

1. For the first five years, the minimum escalator may be based on:

   (a) the forecasted changes in BPA's Priority Firm Power rate or in BPA's Average System Cost at the date of contract execution, filed with the Federal Regulatory Commission on September 30, 1988; or

   (b) actual changes in BPA's Priority Firm Power rate or in BPA's Average System Cost determined in accordance with either subsection 3(a) or 3(b) below.

2. For every rate adjustment date after year five, the minimum escalator shall be based on actual changes determined in accordance with either subsection 3(a) or 3(b) below.

3. The minimum escalation for a contract will be calculated as follows:

   (a) Escalation Based on BPA's Priority Firm Power Rate

   To determine the change in BPA's Priority Firm Power rate the average Priority Firm Power rate or successors rate(s) in mills per kilowatthour in effect on the rate adjustment date specified in the contract shall be divided by average Priority Firm Power rate or successors rate(s) in mills per kilowatthour in effect on the date contract purchases began under this rate schedule. The average PF rate or successor rate(s) shall be calculated at the load factor of the proposed sale, and assume a uniform demand in all months. If there is more than one PF rate in effect, the PF rate shall be determined by a weighting based on forecasted sales in the relevant rate case.

   (b) Escalation Based on BPA's Average System Cost

   Changes in BPA's Average System Cost shall be calculated by dividing BPA's Average System Cost in effect on the rate adjustment date specified in the contract by BPA's Average System Cost in effect on the date contract purchases began under this rate schedule. For purposes of this rate schedule, BPA's Average System Cost shall be determined by dividing BPA's total system costs by BPA's total system sales. BPA's total system costs and total system sales are defined in section IV.D. of the GRSPs.

B. Early Termination Charge

If BPA and a purchaser agree to a rate where in each year of the contract the cumulative present value of the projected contract revenues through that year is not equal to or greater than the cumulative present value revenues at the floor projection as specified in section II.A. and the purchaser has an option to terminate the sale, the purchaser shall be subject to an early termination charge. Such a charge shall be greater than or equal to the difference between the floor revenues projected for that sale at the time the contract was executed and the contract revenues in each year over the period beginning from the date purchases began through the termination date with interest compounded quarterly, as determined by BPA's Office of Financial Management. Interest will continue to apply to any remaining balance until the total termination charge obligation is satisfied. The termination charge shall be payable in a lump sum within 30 days after the date the sale terminates unless an alternative payment schedule is otherwise mutually agreed to by BPA and the purchaser. Any late payment shall be subject to an additional late payment charge in accordance with section VI.G.4. of the GRSPs.

C. Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for the long-term purchase of Surplus Firm Power [and Firm Displacement Power] on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSP's). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the MSL-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NF-89

NONFIRM ENERGY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. This schedule also applies to energy delivered for emergency use under the conditions set forth in section V.A of the General Rate Schedule Provisions (GRSPs). BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. Schedule NF-89 supersedes Schedule NF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The average cost of nonfirm energy is 18.0 mills per kilowatthour. The NF-89 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost. All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap defined in section IV.C of the GRSPs.

A. Standard Rate

The Standard rate is any offered rate not to exceed 21.6 mills per kilowatthour.

B. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

C. Incremental Rate

The Incremental rate is the Incremental Cost of energy plus 2.0 mills per kilowatthour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

D. Contract Rate

The Contract rate is 14.9 mills per kilowatthour of billing energy.

SECTION III. ADJUSTMENTS TO RATES

A. Guaranteed Delivery Surcharge

A surcharge of 2.0 mills per kilowatthour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

B. Intertie Charge

Rate offers, under any of the rates specified above, greater than or equal to 18.0 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie.

SECTION IV. BILLING FACTORS

The billing energy for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

SECTION V. APPLICATION AND ELIGIBILITY

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or a combination of these rates may be in effect.

A. Standard Rate

The Standard rate:

1. is available for all purchases of nonfirm energy; and
2. applies to nonfirm energy purchased pursuant to the Relief from Overrun Exhibit to the power sales contract.

B. Market Expansion Rate

1. Application of the Market Expansion rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. have a displaceable resource, displaceable purchase of electricity, or

b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:

a. shutdown or reduction of the output of the displaceable resource in an amount equal to the amount of Market Expansion rate energy purchased; or

b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion rate

a. When only one Market Expansion rate is offered:

Purchasers qualifying under section V.B.2. who purchased nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.0 mills per kilowatthour.

b. When more than one Market Expansion rates are offered:

Purchasers qualifying under section V.B.2. who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying alternative fuel source is lower than the Standard rate plus 4.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below purchaser's qualifying decremental cost minus 4.0 mills per kilowatthour.

C. Incremental Rate

The Incremental rate applies to sales of energy:

1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;

2. that BPA may at its option not produce or purchase; and

3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) less 2.0 mills per kilowatthour.

D. Contract Rate

The Contract rate applies to contracts (except power sales contracts offered pursuant to sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. for the sale of nonfirm energy; or

2. for determining the value of energy.

E. Western Systems Power Pool Transactions

BPA may make available nonfirm energy for transactions under the Western Systems Power Pool (WSPP) agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and shall be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside that agreement.

F. End-User Rate

BPA may agree to a rate or rate formula for nonfirm energy purchases by end-users. Such rate or rate formula shall be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION VI. DELIVERY

A. Rate of Delivery

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. Guaranteed Delivery

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis.

Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation or transmission losses.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the average cost of nonfirm energy is 99.6 percent FBS and 0.4 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SS-89

SHARE-THE-SAVINGS RATE

SECTION I. AVAILABILITY

This rate schedule is available for the contract purchase of Nonfirm Energy under an experimental rate and is limited to the term of the rate experiment. Nonfirm Energy will be made available under this rate schedule for use both inside and outside the United States for the displacement of a qualifying resource, displaceable purchase of electricity, or end-user load that can be served with alternate fuel sources. This rate schedule is only available to purchasers who execute a contract with BPA specifying use of the Share-the-Savings Rate. BPA is not obligated to offer Nonfirm Energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. Schedule SS-89 supersedes Schedule SS-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The rate shall be a formula rate based solely or in part on decremental cost information submitted by the purchaser. The rate formula and decremental cost, for purposes of establishing charges under this rate schedule, shall be defined in the applicable contract. The rate formula agreed upon by BPA and the purchaser shall in no event result in a rate higher than the NF Rate Cap defined in section IV.C. of the GRSPs or lower than 1 mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing energy for Nonfirm Energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified in the Share-the-Savings Rate contract.

SECTION IV. APPLICATION AND ELIGIBILITY

A. General Requirements

In order to purchase Nonfirm Energy under the Share-the-Savings Rate, the purchaser must:

1. have executed a contract specifying application of the Share-the-Savings Rate Schedule.
2. have a displaceable resource, displaceable purchase of electricity, or be an end-user load with a displaceable alternate fuel source. End-user loads with alternate fuel sources may not use the Decremental Cost of a displaceable purchase of electricity to qualify for this rate.

B. BPA Service Priority

Offers of Nonfirm Energy under this rate schedule shall be made pursuant to the terms and conditions set forth in the Share-the-Savings rate contract. BPA will sell Nonfirm Energy under this rate schedule consistent with regional and public preference.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SS-89 rate is not based on the cost of BPA resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE RP-89

RESERVE POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of power:

A. in cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied;

B. for which BPA determines no other rate schedule is applicable; and

C. to serve a purchaser's firm power load in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States. This rate schedule supersedes Schedule RP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $3.64 per kilowatt of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

25.3 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

A. Billing Demand

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

B. Billing Energy

The billing energy shall be the Contract Demand multiplied by the number of hours in the billing month, if use of the Contract Demand for determining billing energy is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

SECTION IV. POWER FACTOR ADJUSTMENT

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The RP-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

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SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 1989 rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request FERC approval effective October 1, 1989. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for two years: PF-89, IP-89, SI-89, CE-89, CF-89, NR-89, SS-89, NF-89, and RP-89. The VI-87 rate schedule reflects adjustments of and supplements to the rate schedule VI-86 and associated GRSPs (which are to be in effect for 7 years). Sections III.A and VI.J of the VI-87 rate schedule are to be in effect for an additional 2 years. BPA proposes that rate schedule SI-89 be effective 2 years, except for the Special Industrial Offpeak rate provision, which is to remain in effect through June 30, 1990, pursuant to an Amendatory Agreement between BPA and Hanna Nickel Smelting Company executed July 1, 1985.

BPA proposes that the SP-89 rate schedule, and the GRSPs associated with this schedule, be effective for 5 years. BPA proposes that the Nonfirm Energy Rate Cap be effective for 12 years. BPA proposes that the MSL-87 and the GRSPs associated with this schedule be effective December 1, 1988, for contracts executed on or before October 1, 1990.

B. General Provisions

These 1989 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA's 1987 rate schedules (which became effective October 1, 1987) to the extent stated in the Availability section of each 1989 rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Northwest Power Act. All sales of power made under these rate schedules are subject to the following acts as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Northwest Power Act.

SECTION II. TYPES OF BPA SERVICE

A. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for resale to ultimate consumers, or for direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies. (Construction, test and start-up, and station service are defined in section V.B of these GRSPs.)

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount or value of power to be exchanged.

Power purchased under the power rate schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

Priority Firm Power is not available to serve New Large Single Loads.

B. New Resource Firm Power

New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:

1. for any New Large Single Load,
2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and
3. for construction, test and start-up, and station service for facilities owned or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

C. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser pursuant to the DSI's power sales contract and subject to:

1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and
2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

D. Special Industrial Power

Special Industrial Power is electric power which BPA will make continuously available to any DSI that quali-

fies for the Special Industrial Power rate pursuant to section 7(d)(2) of the Northwest Power Act. This power is similar in nature to Industrial Firm Power, but is subject to greater restriction by BPA. Special Industrial Power is made available to the qualifying DSI upon adoption of, and subject to, an amendment modifying its power sales contract.

E. Auxiliary Power

Auxiliary Power is that power which a DSI requests and which BPA agrees to make available to serve that portion of the DSI's load which is in excess of the DSI's Operating Demand for Industrial Firm Power or Special Industrial Power.

F. Firm Capacity

Firm Capacity is capacity that BPA assures will be available in the amount(s) and during the period(s) specified in the power sales contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

G. Surplus Firm Power

Surplus Firm Power is firm energy, firm energy with capacity, and firm capacity (capacity with energy return requirements) in excess of the amount required to meet BPA's existing contractual obligations to provide firm service. Surplus Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Such power, however, may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

H. Nonfirm Energy

Nonfirm Energy is supplied or made available by BPA to a purchaser under an arrangement that does not have the guaranteed continuous availability feature of firm power. Nonfirm energy is mostly sold under the Nonfirm Energy rate schedule, NF-89. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS-89, which is available as an experimental rate for contract purchase.

In addition, BPA also can make nonfirm energy available under the Nonfirm Energy rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements.

However, Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

I. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. in cases where the purchaser's power sales contract states that the rate for Reserve Power shall be applied;
2. to provide service when no other type of power is deemed applicable; and
3. to serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSPs (section V.E).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. Billing Factors for Demand

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section. Measured Demand shall be that portion of the metered or scheduled demand that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand or the scheduled demand, as hereinafter defined. The Measured Demand shall be determined on either a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

a. Metered Demand

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

(1) at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein. In determining the metered demand, BPA shall exclude any abnormal integrated demands due to or resulting from:

(1) emergencies or breakdowns on, or maintenance of, the Federal system facilities, and

(2) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

b. Scheduled Demand

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) to each system for which scheduled demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Ratchet Demand

The Ratchet Demand in kilowatts shall be the maximum demand established during a specified period of time either during or prior to the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. For utilities purchasing under the PF or NR rate schedules, the Ratchet Demand is based on the highest demand during prior billing months. When the Ratchet Demand is used as a billing factor, BPA shall have specified in the appropriate schedules or GRSPs:

a. the period of time over which the ratchet shall be calculated,

b. the type of demand to be used in the calculation, and

c. the percentage (if any) of that demand which will be used to calculate the Ratchet Demand.

3. Contract Demand

The Contract Demand shall be the maximum number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatthours shall be deemed, for the purpose of these GRSPs, to refer to the term "Contract Energy."

4. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

5. Computed Average Energy Requirement

For computed requirements purchasers, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

6. Operating Demand

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI's power sales contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the demand which the purchaser may impose on BPA; and

b. the total amount of energy during a billing month which the DSI is entitled to purchase from BPA.

7. Curtailed Demand

A Curtailed Demand is the number of kilowatts of industrial power (Industrial Firm Power or Special Industrial Power) during the billing month which results from the DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of industrial power may curtail its demand according to the terms of its power sales contract (which permits up to three levels of Curtailed Demand each month).

8. Restricted Demand

Restricted Demand is the number of kilowatts of industrial power (either Industrial Firm Power or Special Industrial Power) that results when BPA has restricted delivery of such power for one clock-hour or more. BPA shall make such restrictions according to the terms of the DSI's power sales contract. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as there are number of restrictions.

9. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's power sales contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power Rate Schedule at the Standard Industrial Rate. Auxiliary Power sales to DSIs electing to purchase under the Variable Industrial Power Rate Schedule (VI-87) shall be made at the rate determined pursuant to section III of the VI-87 rate schedule. Auxiliary Power sales to DSIs purchasing under the Special Industrial Rate will be made only at the Standard Special Industrial Power Rate.

10. BPA Operating Level

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power (Industrial Firm Power or Special Industrial Power) for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;

b. Curtailed Demand; or

c. Restricted Demand.

The weighted average BPA Operating Level for each DSI can be determined by summing the hourly BPA Operating Levels and dividing by the number of hours in the billing month.

Each DSI must request service from BPA for each billing month in accordance with the terms of the power sales contract. The requested level of service will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request and BPA may agree to a level of service for the Offpeak Periods other than that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an unauthorized increase.

Any DSI whose Measured Demand, before adjustment for power factor, during any 1 hour exceeds the BPA Operating Level for that hour shall be subject to unauthorized increase charges for each kilowatt-hour of unauthorized increase associated with each overrun.

Only the BPA Operating Level applicable during the Peak Period will be used in determining the Billing Demand for power purchased under the Industrial Firm Power rate schedule, the Variable Industrial Power rate schedule, and the Standard Rate under the Special Industrial rate schedule. During the Peak Period the BPA Operating Level may be no greater than the Operating Demand for the billing month unless the customer has requested, and BPA has agreed to supply, the Auxiliary Demand.

B. Billing Factors for Energy

1. Measured Energy

Measured Energy shall be that portion of the metered or scheduled energy that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy or the scheduled energy, as hereinafter defined.

a. Metered Energy

The metered energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the power sales contract, and delivered to a purchaser:

(1) at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein.

b. Scheduled Energy

The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) for each system for which scheduled energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Contract Energy

The Contract Energy shall be the maximum number of kilowatthours that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract.

C. Billing Adjustments

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters that are ratcheted to prevent reverse registration. These data then shall be adjusted for losses, if applicable, before determination of the average power factor.

When deliveries to a purchaser at any point of delivery either:

a. include more than one class of power, or

b. are provided under more than one rate schedule and it is impracticable to meter the kilowatthours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a low power factor. Such restriction may be made to a point of delivery or to a purchaser's system at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 75 percent.

2. Outage Credit

To the extent that BPA is unable to provide full service to a purchaser during the billing month as a result of interruptions in service due to reasons cited in the General Contract Provisions, BPA shall adjust the charges for those hours for billing demand for such purchaser to reflect BPA's inability to provide full service, provided such adjustment is mandated by the purchaser's power sales contract. The adjustment is provided on a point of delivery basis. To compute the adjustment for noncoincidentally billed systems, BPA shall determine the monthly demand charge(s) for the point(s) of delivery where the outage(s) occurred, multiply by the number of hours of outage, and divide by the total number of hours in the billing month. For coincidentally billed points of delivery, the adjustment shall apply only to those points of delivery at which BPA was unable to provide full service. For partial outages (such as an outage on one feeder in a substation with several feeders), BPA shall determine an equivalent interruption in order to arrive at the number of hours to be used in the calculation of the credit.

3. Low Density Discount (LDD)

a. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power purchased under the Priority Firm Power rate schedule by eligible purchasers as defined in section b, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year. Retroactive billing for the LDD may be required if the data are

not available by the January billing date. The level of the discount shall be determined from the following ratios:

(1) the purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses, but excluding nonfirm sales to nonfirm retail loads, such as boiler loads served under BPA's alternate fuel policy) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

(2) the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the number of pole miles of distribution line at the end of such year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on data provided in the purchaser's annual financial and operating report. In calculating these ratios, BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see a.(1) and a.(2) above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. Low Density Discounts issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

b. Eligibility Criteria

To qualify for a discount, the purchaser must meet all six of the following eligibility criteria:

(1) the purchaser must serve as an electric utility offering power for resale;

(2) the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the region served by BPA;

(3) the purchaser's average retail rate for the reporting year must exceed the average Priority Firm Power rate in effect for the qualifying period by 10 percent. For CY 1989, the average Priority Firm Power rate shall be the average of the PF-87 rate for 9 months and the PF-89 Preference rate for 3 months. For CY 1990, the average Priority Firm Power rate shall be the PF-89 Preference rate.

(4) the purchaser's kilowatthour-to-investment ratio (Ratio 3.a.(1)) must be less than 100;

(5) the purchaser's consumers-per-mile ratio (Ratio 3.a.(2)) must be less than 12; and

(6) the purchaser must qualify for a discount based on the criteria in section c, below.

c. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for those discounts are listed below.

(1) Three percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 25 but less than 35; or

(b) the consumers-per-mile ratio is equal to or greater than 5 but less than 7.

(2) Five percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 15 but less than 25; or

(b) the consumers-per-mile ratio is equal to or greater than 3 but less than 5.

(3) Seven percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is less than 15; or

(b) the consumers-per-mile ratio is less than 3.

4. Irrigation Discount

a. Basic Irrigation Discount Principles

A discount of 4.6 mills per kilowatthour shall be applied to the charges for qualifying irrigation energy purchased under the Priority Firm Power and New Resource Firm Power rate schedules, during the billing months of April through October. This discount shall be applied subsequent to calculation of the Low Density Discount, if applicable. Any energy on which the irrigation discount is claimed shall be metered separately by the Purchaser, and used exclusively for agricultural irrigation or drainage pumping.

b. Qualifying Energy Purchases

The qualifying irrigation energy shall be determined as follows:

(1) All irrigation energy must be used exclusively for the purpose of irrigation and drainage pumping on agricultural land and be measured at the end-use irrigation customer's meter. The discount shall apply to the measured energy sales at the end-use.

(2) Energy subject to the discount must be purchased during the billing months of April through October.

(3) Purchasers of exchange energy under the Residential Purchase and Sale Agreement (RPSA) are eligible for the irrigation discount for the portion of their irrigation sales qualifying for the exchange under the RPSA contracts.

(4) General requirements customers are eligible for an irrigation discount for a portion of their irrigation sales equal to the share of their total sales served by BPA firm purchases (i.e., total irrigation and drainage pumping sales multiplied by BPA billing energy for Priority Firm or New Resources firm purchases divided by the total firm utility system requirements for the billing month).

c. Initial Reporting Requirements

Requests for the Irrigation Discount must include the following information:

(1) To receive an irrigation discount, a purchaser must file a request for the discount with its local BPA Area or District office by April 1 each year.

(2) In the request, the purchaser must certify that the irrigation energy is sold exclusively for use in irrigation and drainage pumping on agricultural land and that the discount is passed, in its entirety, to the irrigation consumer, regardless of whether the utility has raised its rates. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.

d. Annual Reporting Requirements

Purchasers shall submit an annual irrigation report to their local BPA Area or District office in order to receive the irrigation discount. Purchasers are required to report information related to monthly irrigation energy sales. If a utility does not read its irrigation meters monthly, the utility must estimate its monthly irrigation sales. These estimates shall be reviewed by BPA area and/or district offices. Purchasers must read their meters within 3 working days of the beginning and ending of the irrigation discount period (April-October). In order to qualify for the discount, the purchaser must submit all data to BPA by December 31 of the calendar year in which the sales occurred. Irrigation reports to BPA shall include the following monthly information for the reporting period:

(1) utility name and period for which the report is being made;

(2) total irrigation sales and total qualifying irrigation energy sales (in kilowatthours) by month;

(3) total qualifying irrigation sales (in kilowatthours) by month under 400 horsepower, for exchanging utilities;

(4) total utility firm system requirements for other than full requirement customers by month (in kilowatthours);

(5) total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatthours ; and

(6) the Purchaser shall list each irrigation and drainage account number in its annual report and whether each irrigation consumer is billed monthly, bimonthly, or seasonally. If the Purchaser is an exchanging utility, the Purchaser shall also identify the size (in horsepower) of the connected load for each active account. A utility may submit monthly reports, if it chooses. In that case, the active list of accounts should be included in the last monthly report submitted.

5. Cost Recovery Adjustment Clause

a. Applicable Rate Schedules

The Cost Recovery Adjustment Clause (CRAC) ap-

plies to the Priority Firm Power (Exchange and Preference) (PF-89), Industrial Firm Power (IP-89), Variable Industrial Power (VI-87), Firm Capacity (CF-89), and New Resource Firm Power (NR-89) rate schedules. A percentage adjustment, labeled as CRAC%, is calculated for specific periods and applied to these rates by various formulas.

b. Evaluation and Adjustment Periods

There are two evaluation and adjustment periods for the Cost Recovery Adjustment Clause.

(1) Period 1

Period 1 is comprised of an evaluation period covering FY 1989 (October 1, 1988, through September 30, 1989) and an adjustment period of January 1, 1990, through September 30, 1990.

After September 30, 1989, BPA shall evaluate its preliminary, unaudited financial position by measuring its FY 1989 net revenues (BPA's total FY 1989 revenues less FY 1989 expenses).

Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

If the net revenues are less than zero for the evaluation period (FY 1989) as specified herein, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1990, and ending September 30, 1990.

(2) Period 2

Period 2 is comprised of an evaluation period covering FY 1990 and an adjustment period of January 1, 1991, through September 30, 1991.

Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

After September 30, 1990, BPA shall evaluate its preliminary, unaudited financial position by measuring its FY 1990 net revenues (BPA's total FY 1990 revenues less FY 1990 expenses). The amount of any CRAC adjustment resulting from Period 1 evaluation shall be subtracted from FY 1990 revenues to obtain the adjusted FY 1990 revenues. The adjusted FY 1990 revenues less FY 1990 expenses equals the adjusted FY 1990 net revenues. If adjusted FY 1990 net revenues are less than zero for Period 2, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1991, and ending September 30, 1991.

c. Formulas for the Cost Recovery Adjustment Clause

(1) Adjustment Calculation

BPA shall determine the net revenue for each evaluation period using the following formulas:

(a) Period 1:

NR1 = revenues - expenses

where:

revenues = total operating revenues (in milions of dollars) from the FCRPS Statements of Revenues and Expenses;

expenses = sum of total operating expenses, net interest expense, and any litigation settlement expenses or other extraordinary expenses shown separately on the FCRPS Statements of Revenues and Expenses (in millions of dollars);

NR1 = FY 1989 net revenues (in millions of dollars).

If NR1 is zero or greater, then there will be no rate adjustment; and

CR1 = zero

If NR1 is less than zero:

CR1 = absolute value of NR1, for Period 1.

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1990, through September 30, 1990:

(i) If CR1 is greater than $29.7 million, then the CRAC% equals the lesser of:

(A) (CR1+12.015)/13.899; or

(B) 10.0 percent.

(ii) If CR1 is less than or equal to $29.7 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

CRAC% = CR1/9.902

(b) Period 2:

NR2 = (revenues-ACR1) - expenses

where:

NR2 = Adjusted FY 1990 net revenues (in millions of dollars); and

ACR1 = The lesser of CR1 or $127.0 million; or equals zero if rates were not adjusted, at the discretion of the Administrator, in Period 1.

If NR2 is zero or greater, then there will be no rate adjustment.

If NR2 is less than zero, then:

CR2 = absolute value of NR2 for Period 2.

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1991, through September 30, 1991:

(i) If CR2 is greater than $33.1 million, then the CRAC% equals the lesser of:

(A) (CR2+12.083)/15.056; or

(B) 10.0 percent.

(ii) If CR2 is less than or equal to $33.1 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

CRAC% = CR2/11.014

d. Application to Irrigation Discount

In addition to the direct application of the cost recovery adjustment percentage (CRAC%) to the irrigation discount, an additional adjustment shall be made so that irrigation loads are not disproportionately affected by a 9-month adjustment period as compared to a 12-month adjustment period. The direct and additional adjustments are reflected in the following formula:

Adjusted Irrigation Discount (in mills per kilowatthour)

$$= 4.6 * \left(1 + \frac{CRAC\%}{100}\right) + (0.046 * CRAC\%)$$

where:

4.6 = Irrigation discount applicable to PF-89 and NR-89, in mills per kilowatthour; and

0.046 = adjustment to account for the disproportionate impact of CRAC on irrigation loads, in mills per kilowatthour per percentage CRAC adjustment.

e. Cost Recovery Adjustment Clause Implementation Process

(1) Within 30 days after the end of FY 1989 and within 30 days after the end of FY 1990, BPA shall make an initial calculation to identify the preliminary, unaudited net revenues.

(2) On or about November 1 of each of the years 1989 and 1990, BPA shall notify interested persons and the purchasers under each applicable rate schedule of BPA's initial findings concerning the net revenues for the evaluation period.

(a) If no adjustment is required, or if the Administrator waives implementation of an adjustment, BPA shall state in the notice the basis for its decision, and no further process will be required.

(b) If BPA determines that an adjustment to applicable rates is required, BPA shall state in the notice the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA. Such documentation, if nonproprietary and/or nonprivileged, shall be available upon request unless unduly burdensome. The notice shall also contain the tentative schedule for the remainder of the implementation process.

(3) On or about November 6, 1989, and November 5, 1990, BPA shall conduct a public meeting in which interested persons and purchasers under each applicable rate schedule may seek off-the-record clarification, calculation, and application of the adjustment amount to spe-

cific rate schedules. For the purpose of further mailings, a list of the names and addresses of interested persons and purchasers (hereafter referred to as "mailing list") shall be compiled at this meeting.

(4) On or about November 10, 1989, and November 9, 1990, purchasers under each applicable rate schedule may submit information requests to BPA regarding the adjustment. The requests shall also be mailed to all persons on the mailing list. BPA shall respond to the requests within 2 working days of their receipt, or as soon as practicable if 2 days is insufficient time within which to respond.

(5) On or about November 17, 1989, and November 16, 1990, interested persons and purchasers under each applicable rate schedule may submit written comments to BPA regarding the adjustment. The comments shall also be mailed to all persons on the mailing list.

(6) On or about December 1, 1989, and November 30, 1990, commenters may respond to any comments.

(7) On or about December 1, 1989, and November 30, 1990, BPA may release, if available, revised preliminary unaudited net revenues and any resulting revised adjustment to applicable rate schedules.

(8) On or about December 15, 1989, and December 14, 1990, BPA shall conduct an on-the-record public comment forum in which interested persons and purchasers under each applicable rate schedule may present oral comments to BPA.

(9) On or about December 20, 1989, and December 19, 1990, BPA shall notify interested persons and purchasers under each applicable rate schedule of the audited net revenue balance, the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA.

(10) If there is a rate adjustment due the CRAC following the FY 1989 evaluation period, it shall be in effect from January 1, 1990, through September 30, 1990.

If there is a rate adjustment due to the CRAC following the FY 1990 evaluation period, it shall be in effect from January 1, 1991, through September 30, 1991.

6. Coincidental Billing

Purchasers of Priority Firm Power and New Resource Firm Power shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule(s) unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purpose of these rate schedules and GRSPs, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery. See the Special Provisions Exhibits of the Power Sales Contract, GCP, E, 17.

7. Conservation Surcharge

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for all power purchased under each rate schedule subject to the surcharge. The PF, CF, and NR rate schedules are subject to the Conservation Surcharge. If only a portion of the customer's service area is subject to the surcharge, then the amount of the surcharge shall equal 10 percent of the total charge for all power purchases multiplied by: (a) the portion of the customer's total retail load that is subject to the surcharge, divided by (b) the customer's total retail load.

D. Billing-Related Definitions

1. Peak Period

The Peak Period includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive. There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday. Any charges based on Peak Period hours shall be computed starting with the 8 a.m. meter reading since this reading applies to the 7 o'clock hour (7 a.m. to 8 a.m.). The 10 p.m. meter reading (for the 9 p.m. to 10 p.m. period) is the last meter reading of the day applicable to the Peak Period.

2. Offpeak Period

The Offpeak Period includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 7 a.m., Monday through Saturday and all hours on Sunday. This definition does not apply to the Special Industrial Offpeak Rate.

SECTION IV. OTHER DEFINITIONS

A. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if it is so designated pursuant to the provisions of its power sales contract.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract.

B. Definitions Relating to Nonfirm Energy Decremental Cost

Unless otherwise specified in a contractual arrangement, decremental cost as applied to Nonfirm Energy transactions shall be defined as:

1. All identifiable costs (expressed in mills per kilowatthour) associated with the use of a displaceable thermal resource or end-user load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

2. All identifiable costs (expressed in mills per kilowatthour) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the purchaser.

C. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for nonfirm energy, including any applicable service charges or rate adjustment, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning October 1, 1987.

2. Monthly Notification of the NF Rate Cap

Prior to the beginning of a calendar month BPA shall perform the calculations contained in section IV.C.3. of these GRSPs to determine the effective NF Rate Cap for that calendar month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. BPA may waive this requirement only if BPA does not intend to offer Nonfirm Energy at prices above BASC at any time during a month. The notification will be given at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap applies. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the period the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC + .30(DEC - BASC)

Where:

BASC = BPA's average system cost, determined by dividing BPA's total system costs by BPA's total system sales. For this rate period BASC has been determined to be 23.2 mills per kilowatthour.

DEC = The Decremental Fuel Cost as determined in accordance with section IV.C.5. of these GRSPs.

4. Determination of BPA's Average System Cost

For purposes of determining BPA's Average System Cost (BASC), the following definition shall apply:

a. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent

general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

5. Determination of Decremental Fuel Cost

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap, a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. The monthly decremental fuel cost shall be:

a. the sum of:

(1) the average California price for gas determined by multiplying the monthly gas use (WGU)developed pursuant to section IV.C.8.a. times the monthly California gas price (MGP) determined pursuant to section IV.C.6 rounded to the nearest tenth of a mill; and

(2) the average California price for petroleum determined by multiplying the monthly petroleum use (WOU) developed pursuant to section IV.C.8.b times the monthly California petroleum price (MOP) determined pursuant to section IV.C.7. rounded to the nearest tenth of a mill.

b. divided by the sum of the monthly gas use (WGU) and monthly petroleum use (WOU) developed in section IV.C.8.a. and b. respectively rounded to the nearest tenth of a mill.

6. California Gas Price

The monthly gas price (MGP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MGP = \frac{AGP * HGP}{10}$$

Where:

AGP = the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HGP = the historical relationship between gas prices in the effective month of the NF Rate Cap (month t) and the month in which the gas prices are reported in EPM (month r) using the following procedures:

a. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California gas price in a. above, by the average monthly California gas price in b. above, and rounding to the nearest one-tenth, or three significant places.

10 = the factor for converting gas prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.

7. California Petroleum Price

The monthly petroleum price (MOP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MOP = \frac{AOP * HOP}{10}$$

Where:

AOP = the last available average oil price for California electric utility plants expressed in cents per million Btu reported in *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HOP = the historical relationship between petroleum prices in the effective month of the NF Rate Cap (month t) and the last month in which the petroleum prices are reported in EPM (month r) using the following procedures:

a. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly

petroleum prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California petroleum price in a. above, by the average monthly California petroleum price in b. above, and rounding to the nearest one-tenth of a percent, or three significant places.

10 = the factor for converting petroleum prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.

8. Weighting Factors

For purposes of determining California fuel prices for the month, gas and petroleum prices will be weighted based on California's historical use of these two alternative fuels.

a. Historical Gas Use in California

The following formula shall be used to determine the weighting factor for gas prices (WGU):

WGU = CGU * HGU

Where:

CGU = the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HGU = the historical relationship between gas consumptions in the effective month of the NF Rate Cap (month t) and the month for which gas consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-gas fired generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of gas in California for the month t as determined in (1) above by the average consumption of gas for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

b. Historical Petroleum Use in California

The following formula shall be used to determine the weighting factor for petroleum prices (WOU):

WOU = COU * HOU

Where:

COU = the monthly net petroleum-fired generation, expressed in gigawatthours, in California in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HOU = the historical relationship between petroleum consumptions in the effective month of the NF Rate Cap (month t) and the month for which petroleum consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be di-

vided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of petroleum in California for the month t as determined in (1) above by the average consumption of petroleum for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

D. Determination of BPA's Average System Cost.

For purposes of determining BPA's Average System Cost (BASC), the following definition shall apply:

1. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

2. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted in each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm or New Resource Firm Power shall pay in accordance with the Nonfirm Energy rate schedule, NF-89, and Emergency Capacity rate schedule, CE-89, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or

2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefore settled under exchange agreements.

B. Construction, Test and Start-Up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.

2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on line and to ensure that the project is working properly.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates During Initial Operation Period—Transitional Service

1. Eligibility for Transitional Service

For an initial operating period, as specified in the power sales contract, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

a. DSIs having new, additional or reactivated plant facilities, and

b. utility purchasers serving industrial purchasers with power purchased from BPA. BPA will provide transitional service to utilities for only those industrial loads for which the demand can be separately metered by the utility and recorded on a daily basis.

2. Calculation of the Daily Demand

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the Daily Demands as adjusted for power factor.

Demand for each day shall be defined as 100 percent of the Measured Demand for the day (regardless of whether such Measured Demand occurs during the Peak Period or the Offpeak Period).

3. Billing for Transitional Service

Utilities receiving transitional service shall provide BPA with Daily Demand information for the industrial consumer for whom transitional service is provided. To compute the power bill for the point of delivery which includes the load being served with transitional service, BPA shall, at its discretion, either:

a. determine the demand for the pertinent point of delivery without the industrial load and then add the average daily demand for such industrial load; or

b. bill the entire point of delivery on a daily demand basis.

Daily demand billing shall not affect the level of any curtailment charge or energy charge assessed by BPA.

D. Changes in a DSI's BPA Operating Level

If a DSI requests a waiver regarding the notice requirements specified in the DSI's power sales contract for a voluntary change in its BPA Operating Level, and if BPA does not grant the waiver, or if the DSI fails to give notice of such a change and does not request a waiver, the DSI shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

E. Restriction of Deliveries

Deliveries of capacity or energy to any purchaser may be restricted when operation of the facilities used by BPA to serve such purchaser is:

1. suspended,
2. interrupted,
3. interfered with,
4. curtailed, or
5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

SECTION VI. BILLING INFORMATION

A. Determination of Estimated Billing Data

If the amounts of capacity, energy, or the 60-minute integrated demands for energy purchased from BPA must be estimated from data other than metered or scheduled quantities, historical patterns, and pertinent weather data, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, derived by any method, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

B. Load Shift and Outage Reports

Load shift and outage reports must be submitted to BPA within 4 days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. If customer reports are not received in a timely manner, BPA has the option to withhold load shift or outage credit.

C. Billing for New Large Single Loads

Any BPA customer whose total load includes one or more New Large Single Loads (NLSL) shall be billed for the NLSL(s) at the New Resource Firm Power Rate. The power requirements associated with the NLSL shall be established in a manner consistent with the provisions of this section.

The purchaser shall warrant to BPA that NLSLs are separately metered. The metering must include provisions for determining:

1. the NLSL demand during BPA's diurnal capacity billing periods,
2. the NLSL energy during BPA's energy billing periods, and
3. the NLSL reactive energy for the billing month.

The design for the metering equipment for the NLSL must be approved by BPA. Testing and inspections of such metering installations shall be as provided in the General Contract Provisions.

On a monthly basis, each purchaser of New Resource Firm Power shall report to BPA the quantity of power used by the NLSL during the purchaser's billing period. Data provided to BPA by the purchaser must be submitted to BPA within 2 normal working days of the date the purchaser reads the meters. BPA may elect to adjust the NLSL data for losses from the point of metering to the closest BPA point of delivery for the purchaser.

D. Determination of Measured Demand

1. For points of delivery with fully operational metering under the Revenue Metering System (RMS), demand shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.
2. For points of delivery that do not have RMS metering, demand shall be measured from 0000 hours on the first complete (24 hour) day of the available metering data through 2400 hours on the last complete day of the available metering data. Billing demand will be determined from the period of available metering data that most closely matches the official billing period of the customer.

E. Determination of Measured Energy

1. For points of delivery with fully operational metering under RMS, energy shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.
2. For points of delivery that do not have RMS metering, measured energy shall be the quantity of usage recorded on the meter between meter readings.

F. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less than or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately.

The calendar month in which the purchaser's meter is scheduled to be read determines the billing month. (Thus, a bill associated with a meter scheduled to be read on April 10 would be an April bill.) The charges for the winter and summer periods identified in the rate schedules apply to the purchaser's billing months.

G. Payment of Bills

Bills for power shall be rendered monthly by BPA. Failure to receive a bill shall not release the purchaser from liability for payment. Bills for amounts due BPA of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). This requirement holds also for revised bills (see section 6 below). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the purchaser), the due date shall be the next following business day.

4. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto under such contract.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

As necessary, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than the

amount of the bill which it is replacing, the additional amount will be billed on a separate bill, and the date of the revised bill shall be its date of issue.

SECTION VII. VARIABLE INDUSTRIAL RATE PARAMETERS AND ADJUSTMENTS

A. Monthly Average Aluminum Price Determination

1. Calculation of the Monthly Billing Aluminum Price

The monthly billing aluminum price shall be determined by BPA for each billing month. For purposes of this rate schedule, the monthly billing aluminum price shall be based on the average price of aluminum in U.S. markets during the third calendar month prior to the billing month. The average price of aluminum in U.S. markets shall be defined as the average U.S. Transaction Price reported for the month by *Metals Week,* in cents per pound, rounded to the nearest tenth of a cent.

2. Notification of the Monthly Average Aluminum Price

BPA shall provide, 45 days prior to the billing month, written notification to purchasers under this rate schedule of the monthly billing aluminum price to be used for billing purposes. Upon written request *supporting documentation shall be provided.*

3. Changes in Aluminum Price Indicators

In the event that BPA determines that factors outside its control render the monthly average U.S. Transaction Price unusable as an approximation of U.S. market prices, BPA may develop and substitute another indicator for prices in U.S. markets. BPA shall notify interested parties of its intent to do so at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason for the substitution and specify the replacement indicator it intends to use. BPA also shall describe the methodology to determine the monthly billing aluminum price to be used for billing purposes under this rate schedule and shall provide the necessary data to be used in the calculation. Interested persons will have until close of business 3 weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final methodology and the substitute aluminum price index to differ from those proposed. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month the new indicator shall be effective.

B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices

On July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices, as stated in section III.B of the rate schedule, shall be subject to change for billing purposes as herein described. The term "annual adjustment date" shall refer to July 1 of each year.

1. Implementation Procedures

Beginning in 1987 and every year thereafter, prior to April 1 of that year, BPA shall provide the purchasers under this rate schedule preliminary written estimates of proposed adjustments to the Lower and Upper Pivot Aluminum Prices. By the last working day of the month of April, BPA shall notify interested parties in writing of BPA's revised determinations concerning changes to the Lower and Upper Pivot Aluminum Prices. BPA shall describe how the adjustments were determined and provide the data used in the calculations. In addition to written notification, BPA may, but is not obligated to, hold a public comment forum to clarify its determinations and solicit comments. Interested persons may submit comments on the determinations to BPA and other parties. Comments will be accepted until close of business on the last working Friday in May. Consideration of comments and more current information may result in the final adjustment differing from the proposed adjustment. By June 30 of each year, BPA shall notify all VI purchasers, *those parties that submitted comments, and* parties that requested notification, of the final determination.

2. Annual Adjustment Procedures

a. Annual Adjustment of the Lower Pivot Aluminum Price

Beginning with the July 1, 1987, annual adjustment date, for each year that the Variable Industrial rate is in effect, the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Lower Pivot Aluminum Price shall be revised by multiplying 59 cents per pound by the Cost Escalation Index described in section VII.B.3.b of these GRSPs and rounded to the nearest tenth of a cent. The revised Lower Pivot Aluminum Price shall replace the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

b. Annual Adjustment of the Upper Pivot Aluminum Price

For each year that the Variable Industrial rate is in effect, the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule shall be adjusted on the July 1 annual adjustment date.

(1) Annual adjustment for the period beginning July 1, 1987, and ending June 30, 1991

The Upper Pivot Aluminum Price shall be revised by multiplying 72 cents per pound by the Cost Escalation Index described in section VII.B.3.c of these GRSPs and rounded to the nearest tenth of a cent. The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

(2) Annual Adjustment for the period beginning July 1, 1991, and ending June 30, 1993

The Upper Pivot Aluminum Price will be adjusted such that the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs is the midpoint between the adjusted Upper Pivot Aluminum Price and the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 below, except as limited to the greater of 65 cents per pound or the adjusted Lower Pivot Point for the year.

The Upper Pivot Aluminum Price shall equal the greater of:

(a) (2)(AAP) - ALP:

where

AAP = the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs.

ALP = the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 of these GRSPs.

(b) 65.0 cents per pound escalated to current dollars using the Cost Escalator for the Upper Pivot Aluminum Price described in section VII.B.3.c of these GRSPs.

or

(c) The adjusted Lower Pivot Aluminum Price for the year.

The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 months.

3. Cost Escalators

a. The cost indices described below shall be used in calculating the appropriate cost escalators. Each index shall be rounded to the nearest one-tenth of a percent, or three significant places.

(1) Electricity Cost Index

The average VI-87 rate in mills per kilowatthour based on the Plateau Energy Charge and the Discount for Quality of First Quartile Service in effect on the April 1 preceding the annual adjustment date and a load factor of 98.5 percent; divided by 22.8 mills per kilowatthour (the average VI-86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) Labor Cost Index

The annual average hourly earnings for the U.S. primary aluminum industry (SIC 3334) over the previous complete calendar year, from the Employment and Earnings, published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS), divided by $14.20 per hour (the value of SIC 3334 earnings reported for 1985).

(3) Alumina Cost Index

The annual average of the monthly billing aluminum prices described in section VII.A of the GRSPs for the previous 1-year period beginning July 1 through June 30 divided by 50.8 cents per pound (the average U.S. Transaction price over the period April 1985 through March 1986).

(4) Other Costs Index

The annual average GNP Implicit Price Deflator for the previous complete calendar year, as published by the U.S. Department of Commerce, Bureau of Economic Analysis, divided by 1.115 (the value of the GNP Implicit Price Deflator for 1985 with 1982 = 1.000).

In the event the indices delineated above are discontinued or revised in a manner that BPA determines renders them unusable for calculating a consistent cost index, BPA will adjust or substitute another similar price index, following advance notification and opportunity for public comment as described in section VII.B.1 of these GRSPs.

b. The Cost Escalator for the Lower Pivot Aluminum Price shall be a weighted average of the four indices contained in section VII.B.3.a above. The following weights shall be assigned each index:

Electricity Cost Index	.30
Labor Cost Index	.20
Alumina Cost Index	.20
Other Costs Index	.30

c. The Cost Escalator for the Upper Pivot Aluminum Price shall be a weighted average of the Electricity Cost and Other Cost Escalators as stated in sections VII.B.3.a.(1) and VII.B.3.a.(4) above. The following weights shall be assigned each index:

Electricity Cost Index	.25
Other Costs Index	.75

4. Average Historical Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, an average historical aluminum price shall be calculated for the period the Variable rate has been in effect. The average historical aluminum price shall be determined following the procedures set forth below:

a. Each monthly billing aluminum price determined pursuant to section VII.A of these GRSPs for the period August 1, 1986, through June 30 immediately preceding the annual adjustment date, shall be escalated to the current year dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly billing aluminum prices shall be divided by the number of months in the period and rounded to the nearest tenth of a cent to obtain the Average Historical Aluminum Price.

5. Average Historical Lower Pivot Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, the average of the Lower Pivot Aluminum Prices for the period the Variable Industrial rate has been in effect shall be calculated following the procedures set forth below:

a. The Lower Pivot Aluminum Price in each month for the period August 1, 1986, through June 30 of the calendar year preceding the annual adjustment date, shall be escalated to the current year's dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly Lower Pivot Aluminum Prices shall be divided by the number of months in the period, and rounded to the nearest tenth of a cent to obtain an Average Historical Lower Pivot Aluminum Price.

6. Price Deflator Procedures

For purposes of converting nominal dollars to real dollars in the calculation of the Average Historical Aluminum Price and the Average Historical Lower Pivot Aluminum Price, the following Price Deflator procedures shall be used:

a. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months July through December shall be inflated by multiplying the price by the ratio of the GNP Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year in which the price occurred.

b. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months January through June shall be inflated by multiplying the price by the ratio of the Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year prior to the year in which the price occurred.

Each price shall be rounded to the nearest tenth of a cent.

11-3-83

GCP Form PSC (SW) - 1

GENERAL CONTRACT PROVISIONS

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IN REFERENCE TO MEANING

1. Definitions. The definitions in the body of this contract and the following additional definitions apply to this exhibit.

(a) "Contractor" means the Purchaser.

(b) "Energy Requirements of Any Pacific Northwest Customer" means the full requirements for electric energy of (1) any purchaser from Bonneville for direct consumption in the Pacific Northwest, and (2) any Non-Federal Utility in that region in excess of (A) the hydroelectric energy available for its own use from its generating plants in the Pacific Northwest; (B) any amount of energy included in the resources of such utility which (i) is included in the firm resource exhibit of any Bonneville customer's power sales contract, (ii) was disposed of by such utility outside the Pacific Northwest, (iii) increases the firm energy requirements of such utility or any other Bonneville customer as a result of such disposition, and (iv) could have been conserved or otherwise retained for service to loads in the Pacific Northwest, in Bonneville's determination, through reasonable measures taken by such utility; and (C) any additional energy available for use in the Pacific Northwest which, under a then existing contract, the utility (i) can obtain at no higher incremental cost than the rate charged by the Bonneville, or (ii) is required to accept.

(c) "Excess Energy" means electric energy which the Purchaser determines in its sole discretion that it has available for sale to Bonneville in excess of its other obligations.

(d) "Extra-High Voltage Transmission Lines" means the transmission lines and related terminal facilities described in the Intertie Report of the Secretary of the Interior dated June 1964, as amended and supplemented.

(e) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(f) "Federal Energy Regulatory Commission" means the Federal Energy Regulator Commission or its successor.

(g) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatthours delivered at any point during any clock hour.

(h) "Non-Federal Utility" means any utility not owned or controlled by the United States, including any entity (1) which such a utility owns or controls, in whole or in part, or is controlled by; (2) which is controlled by those controlling such utility; or (3) of which such utility is a member.

(i) "Pacific Northwest" means the same as such term is defined in P.L. 96-501.

(j) "Peaking Energy" means the electric energy accompanying the delivery of Surplus Peaking Capacity.

(k) "Peaking Replacement Energy" means that portion of the Peaking Energy which is not Surplus Energy and which Bonneville requires the Purchaser to replace.

(l) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(m) "Provisional Energy" means electric energy generated on the Federal System which can be conserved, for which there is no immediate demand in the Pacific Northwest at any established rate, but for which Bonneville determines there may be a demand in meeting the future energy requirements of the Pacific Northwest.

(n) "Provisional Replacement Energy" means energy which the Purchaser is obligated to make available to Bonneville by reason of receipt of Provisional Energy.

(o) "Surplus Energy" means electric energy generated at Federal hydroelectric plants, excluding the Canyon Ferry Project, in the Pacific Northwest or generated on the Federal System which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate or for which there is no market in the Pacific Northwest at any rate established for the disposition of such energy.

(p) "Surplus Peaking Capacity" means electric peaking capacity at Federal hydroelectric plants, excluding the Canyon Ferry Project, in the Pacific Northwest or electric peaking capacity on the Federal System for which there

is no demand in the Pacific Northwest at any established rate or for which there is no demand in the Pacific Northwest at the rate established for the disposition of such capacity.

(q) "Treaty" means the Treaty between the United States and Canada relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington January 17, 1961.

(r) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Purchaser's works, system, or other physical facilities; the Federal System Facilities or the physical facilities owned, controled or used by any non-Federal Utility in the Pacific Northwest resulting in such utility's inability to meet its requirements; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Non-Federal Utility to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Purchaser or Bonneville or any Non-Federal Utility by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Non-Federal Utility, causing failure, damage, destruction or reduction of transmission capacity of any works, system or facilities of such party or Non-Federal Utility; the word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Non-Federal Utility, and which are issued in any bona fide proceeding by:

(i) any duly constituted court of general jurisdiction; or

(ii) any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Non-Federal Utility has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jurisdiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Non-Federal Utility in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Non-Federal Utility, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

The provisions of this definition relating to Non-Federal Utilities in the Pacific Northwest shall be applicable only to the delivery of Surplus Energy.

2. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained in this exhibit, the former shall prevail.

(b) If a provision in the General Rate Schedule Provisions incorporated in the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit is in conflict with a provision contained in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party hereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions of this contract which it would otherwise have.

IN REFERENCE TO COMPUTATION OF CHARGES

3. Measurements. Each measurement of each meter mentioned in this contract shall be the measurement automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any

such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

4. Adjustment for Change of Conditions. Changes in conditions may occur after the date of execution of this contract which substantially affect factors required by this contract to be used in determining (a) the charge for a service or for use of facilities provided by Bonneville other than charges for the sale of electric power and energy; or (b) the amount of losses from the transmission or transformation of electric power or energy. Such factors will then be changed in an equitable manner which will conform to such changes in conditions.

5. Adjustment for Inaccurate Metering. If any meter mentioned in this contract fails to register, if the measurement made by such meter during a test made as provided in section 18 hereof varies by more than one percent from the measurement made by the standard meter used in such test or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such inaccurate measurements were made, if such period can be determined. If such period cannot be determined the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter; or (b) 6 months. Such corrected measurements shall be used to recompute the amounts due from the Purchaser for the electric power and energy made available under this contract during such period and shall be used, when applicable, in future billings to the Purchaser. If the total amount due from the Purchaser for such period as recomputed varies from the total amount previously billed by Bonneville, Bonneville shall adjust the wholesale power bill(s) as soon as practicable.

IN REFERENCE TO RATES

6. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the sale and disposition of electric power, capacity or energy sold pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" mean any date as specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Purchaser 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Purchaser; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Purchaser shall pay Bonneville for the electric power and energy made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this

contract, and in accordance with the terms thereof, and of the General Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville rates. Rates shall be applied in accordance with the terms thereof, the General Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

7. Retail Rates.

(a) Copies of the Purchaser's schedules of retail rates, including special contract rates, if any, in effect when this contract is executed, and those hereafter adopted, endorsed with the effective date thereof, shall be furnished to Bonneville, and Bonneville shall keep said rates on file. The Purchaser agrees to serve each of its consumers at, and in accordance with, the rates, charges, and provisions set forth in the applicable rate schedules on file where and as required by law or on file in Bonneville's office. Notice of the intent to change retail rates shall be given to Bonneville either 45 days prior to their effective date or as soon as the regulatory process allows or shall be mailed to Bonneville on the same day as a notice of a rate change given to a state regulatory authority by the Purchaser, whichever will result in the later receipt of such notice by Bonneville.

(b) The retail rates and charges shall be reasonable and nondiscriminatory, consistent with the principles of the Bonneville Project Act, subject to the right of the Purchaser to adopt retail rates designed to achieve cost-effective conservation or renewable resources; provided, however, that rates and charges which have been approved in accordance with the procedures of a state regulatory agency having jurisdiction shall be deemed

prima facie reasonable and nondiscriminatory. The Purchaser shall maintain records containing the data, analyses, and other factors which are used to develop and form the basis for its proposed or final retail rates. At Bonneville's request, such records as are available for public inspection shall be supplied during the rate development process or after the rates have been adopted.

IN REFERENCE TO DELIVERY OF POWER

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power or energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Purchaser at the Point(s) of Delivery and at such voltage(s) as specified. Unless otherwise agreed, delivery at more than one voltage shall constitute delivery at more than one point.

10. Metered Quantities. The amount(s) of energy, Integrated Demands therefor and amount(s) of reactive energy delivered to the Point(s) of Delivery during each month shall be determined from measurements made by meters installed for such Point(s) of Delivery in the circuit specified.

11. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

12. Continuity of Service.

(a) The Purchaser or Bonneville may temporarily interrupt or reduce deliveries of electric power or energy if the Purchaser or Bonneville determines that such interruption or reduction is necessary or desirable in case of system emergencies, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on, the Purchaser's facilities or the Federal System. Except in case of emergency and in order that the Purchaser's operations will not be unreasonably interfered with, Bonneville shall give reasonable notice to the Purchaser of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent Bonneville has knowledge thereof. The Purchaser or Bonneville shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

(b) If the delivery of Peaking Replacement Energy or Provisional Replacement Energy to Bonneville has been interrupted or curtailed pursuant to this section, the amount of energy which would otherwise have been delivered shall be made available as soon as practicable after resumption of deliveries, upon request by Bonneville.

IN REFERENCE TO PAYMENT FOR POWER

13. Payment of Bills. Bills for power shall be rendered monthly and shall be payable at Bonneville's headquarters. Failure to receive a bill shall not release the Purchaser from liability for payment. Each calculated monetary amount in a wholesale power bill shall be rounded to a whole dollar

amount, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If Bonneville is unable to render the Purchaser a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed by the final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same payment provisions as shall a final bill.

Bills not paid in full on or before the date specified in the Payment of Bills section, or its successor, of the General Rate Schedule Provisions incorporated in the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit shall bear additional charges as specified therein.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the Purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

Bonneville may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the Purchaser, but such cancellation shall not affect the Purchaser's liability for any charges accrued prior thereto.

14. Determination of Estimated Billing Data. If the amounts of power or energy which have been delivered hereunder must be estimated from data other

than metered quantities, scheduled quantities or tabulations of hourly interchange prepared by the Purchaser, Bonneville and the Purchaser shall agree on estimated billing data to be used in preparing the bill.

IN REFERENCE TO USE OF POWER

15. Resale of Power. The Purchaser shall not resell surplus peaking capacity and surplus energy delivered under this contract except to those consumers and utilities within its service area outside the Pacific Northwest to the extent such consumers and utilities are normally dependent on the Purchaser for their firm power supplies.

16. Electric Disturbance.

(a) For the purposes of this section an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain, and use its electric system in conformance with accepted electric utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury, or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury, or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any persons not a party to this contract.

IN REFERENCE TO FACILITIES

17. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

18. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 5 hereof. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired, or replaced to provide accurate metering.

19. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

20. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment and all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other, by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and salvable facilities so installed.

21. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any

reasonable time. Such inspection, or failure to inspect, shall not render such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

MISCELLANEOUS PROVISIONS

22. General Environmental Provision.

(a) Policy. Bonneville in the performance of this contract shall comply with all of its obligations pursuant to the National Environmental Policy Act.

(b) Affirmative Obligations. The parties agree to:

(1) comply fully with all applicable Federal, State, and local environmental laws;

(2) to assist and to cooperate with each other in meeting each other's environmental obligations, to the fullest extent economically and technically practicable and mutually agreeable; and

(3) provide upon request of the other party a copy of pollution abatement plans as required by the Clean Air Act, by the Clean Water Act, by other Federal statutes, or by an agency having jurisdiction and within a reasonable time submit evidence that such plans have been approved or have not been objected to by agencies with jurisdiction.

(c) Breach of Obligations. A breach of this General Environmental Provision exists only if a final determination, including all appeals, has

been entered by a court or pollution control agency or agencies having jurisdiction that the Purchaser's facility is not in compliance with applicable laws respecting the control and abatement of environmental pollution.

(d) Remedy. Bonneville, after consulting with state or local agencies having jurisdiction may restrict delivery of surplus peaking capacity or surplus energy to the Purchaser pursuant to this contract, if Bonneville determines that:

(1) a breach of this General Environmental Provision exists;

(2) such breach is resulting in a significant adverse effect on the environment;

(3) no governmental agency has jurisdiction or authority to impose sanctions or to seek remedy for such significant adverse effect on the environment; and

(4) restriction of delivery is the only appropriate remedy and bears a reasonable relationship to the breach.

Before restricting delivery of surplus peaking capacity or surplus energy pursuant to this section, Bonneville shall give the Purchaser written notice and a reasonable opportunity to cure the breach and to seek any legal recourse available to the Purchaser.

23. Equitable Treatment of Fish and Wildlife. Constraints on operation of Federal hydroelectric facilities located on the Columbia River or its tributaries which are used to determine amounts of Surplus Energy on the Federal System include those developed for equitable treatment of fish and wildlife along with other purposes for which such system and facilities are operated and managed. Bonneville's determination of amounts of Surplus Energy

shall be based on any existing or future constraints on hydroelectric system operations.

24. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Purchaser.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the

parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 3 above;

(2) the occurrence of changes in conditions for purposes of section 4 above;

(3) the correction of the measurements to be made pursuant to section 5 above;

(4) the occurrence of an abnormal nonrecurring demand and the amount and time thereof; and

(5) whether a party has complied with section 16(b) above.

25. Net Billing. Upon mutual agreement of the parties, payments due one party may be offset against payments due the other party under all contracts between the Purchaser and Bonneville for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such

balance carried forward to be added to the payments due it in a succeeding month.

26. Contract Work Hours and Safety Standards. This contract, if and to the extent required by applicable law or if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated of Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of 8 hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work

performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

27. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by P.L. 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

28. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or

termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or workers' representative of the Contractor's commitments under the Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of subsections (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisons will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

29. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

30. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as specifically provided in this section.

31. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

32. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

33. Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to such contract if made with a corporation for its general benefit.

(WP-PKI-1741c)

EXHIBIT C

P. L. 88–552

Act of August 31, 1964, 78 Stat. 756, 16 U.S.C. 837–837h
[Public No. 552 (S. 1007) – 88th Congress 2d Session]

AN ACT

To guarantee electric consumers in the Pacific Northwest first call on electric energy generated at Federal hydroelectric plants in that region and to guarantee electric consumers in other regions reciprocal priority, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That, as used in this Act —

Pacific Northwest, Federal hydroelectric plants. Definitions.

(a) "Secretary" means the Secretary of the Interior.

(b) "Pacific Northwest" means (1) the region consisting of the States of Oregon and Washington, the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming within the Columbia drainage basin and of the State of Idaho as the Secretary may determine to be within the marketing area of the Federal Columbia River power system, and (2) any contiguous areas, not in excess of seventy-five airline miles from said region, which are a part of the service area of a distribution cooperative which has (i) no generating facilities, and (ii) a distribution system from which it serves both within and without said region.

(c) "Surplus energy" means electric energy generated at Federal hydroelectric plants in the Pacific Northwest which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate.

(d) "Surplus peaking capacity" means electric peaking capacity at Federal hydroelectric plants in the Pacific Northwest for which there is no demand in the Pacific Northwest at any established rate.

(e) "Non-Federal utility" means any utility not owned or controlled by the United States, including any entity (1) which such a utility owns or controls, in whole or in part, or is controlled by, (2) which is controlled by those controlling such utility, or (3) of which such utility is a member.

(f) "Energy requirements of any Pacific Northwest customer" means the full requirements for electric energy of (1) any purchaser from the United States for direct consumption in the Pacific Northwest, and (2) any non-Federal utility in that region in excess of (i) the hydroelectric energy available for its own use from its generating plants in the Pacific Northwest, and (ii) any additional energy available for use in the Pacific Northwest which, under a then existing contract, the utility (A) can obtain at no higher incremental cost than the rate charged by the United States, or (B) is required to accept.

(g) Terms not defined herein shall, unless the context requires otherwise, have the meaning given them in the March 1949 Glossary of Important Power and Rate Terms prepared under the supervision of the Federal Power Commission. [16 U.S.C. 837.]

SEC. 2. Subject to the provisions of this Act, the sale, delivery, and exchange of electric energy generated at, and peaking capacity of, Federal hydroelectric plants in the Pacific Northwest for use outside the Pacific Northwest shall be limited to surplus energy and surplus peaking capacity. At least 30 days prior to the execution of any contract for the sale, delivery, or exchange of surplus energy or surplus peaking capacity for use outside the Pacific Northwest, the Secretary shall give the then customers of the Bonneville Power Administration written notice that negotiations for such a contract are pending, and thereafter, at any customer's request, make available for its inspection current drafts of the proposed contract. [16 U.S.C. 837a.]

Notice to purchasers.

Deliveries.

SEC. 3. (a) Any contract for the sale or exchange of surplus energy for use outside the Pacific Northwest, or as replacement, directly or indirectly, within the Pacific Northwest for hydroelectric energy delivered for use outside that region by a non-Federal utility, shall provide that the Secretary, after giving the purchaser notice not in excess of sixty days, will not deliver electric energy under such contract whenever it can reasonably be foreseen that such delivery would impair his ability to meet, either at or after the time of such delivery, the energy requirements of any Pacific Northwest customer. The purchaser shall obligate himself not to take delivery of or use any such energy to supply any load under such conditions that discontinuance of deliveries from the Pacific Northwest in sixty days would cause undue hardship to the purchaser or in his territory, and, further, the purchaser shall acknowledge full responsibility if any such hardship occurs. Deliveries by a non-Federal utility from its generating plants in the Pacific Northwest for use on its own distribution system in an area outside but contiguous to the Pacific Northwest (not including any extension of its outside service area by merger or acquisition after the effective date of this Act) shall not be deemed deliveries by such utility for use outside the Pacific Northwest.

(b) Electric energy generated at Federal hydroelectric plants in the Pacific Northwest which can be conserved, for which there is no immediate demand in the Pacific Northwest at any established rate, but for which the Secretary determines there may be a demand in meeting the future requirements of the Pacific Northwest, may be delivered for use outside that region only on a provisional basis under contracts providing that if the Secretary determines at a subsequent time that, by virtue of prior deliveries under such contract, the Secretary is or will be unable to meet the energy requirements of any Pacific Northwest customer, the purchaser will return the full amount of energy delivered to him, or such portion or portions thereof as may be required, at such time or times as may be specified by the Secretary, except that the Secretary shall not require return during the purchaser's daily peak periods. The Secretary shall require the return of the energy provisionally delivered hereunder, to such extent and at such times, as may be necessary to meet demands at any established rate for use within the Pacific Northwest.

(c) Any contract for the disposition of surplus peaking capacity shall provide that (1) the Secretary may terminate the contract upon notice not in excess of sixty months, and (2) the purchaser shall advance or return the energy necessary to supply the peaking capacity, except that the Secretary shall not require such advance or return during the purchaser's daily peak periods. The Secretary may contract for the sale of such energy to the purchaser, in lieu of its return, under the conditions prescribed in subsection (a) of this section. Contracts.

(d) The Secretary, in making any determination of the energy requirements of any Pacific Northwest customer which is a non-Federal utility having hydroelectric generating facilities, shall exclude any amounts of hydroelectric energy generated in the Pacific Northwest and disposed of outside the Pacific Northwest by the utility which, through reasonable measures, could have been conserved or otherwise kept available for the utility's own needs in the Pacific Northwest. The Secretary may sell the utility as a replacement therefor only what would otherwise be surplus energy. [16 U.S.C. 837b.]

SEC. 4. Any contract of the Secretary for the sale or exchange of electric energy generated at, or peaking capacity of, Federal hydroelectric plants in marketing areas outside the Pacific Northwest for use within the Pacific Northwest shall be subject to limitations and conditions corresponding to those provided in sections 2 and 3 for any contract for the sale or exchange of hydroelectric energy or peaking capacity generated within the Pacific Northwest for use outside the Pacific Northwest. [16 U.S.C. 837c.] Limitations.

SEC. 5. Without regard to the limitations specified in sections 2 and 3 of this Act, the Secretary may enter into contracts for the exchange with areas other than the Pacific Northwest of (1) surplus energy during the Pacific Northwest storage refill period, (2) any hydroelectric energy during the Pacific Northwest storage refill period which will be returned to the Pacific Northwest in equal amounts during the same Pacific Northwest refill period or the succeeding storage drawdown period, (3) any hydroelectric energy which will be returned to the Pacific Northwest in equal amounts during the same Pacific Northwest storage drawdown period, (4) hydroelectric peaking capacity, or (5) surplus peaking capacity for energy. All benefits from such exchanges, including resulting increases of firm power, shall be shared equitably by the areas involved, having regard to the secondary energy and other contributions made by each. [16 U.S.C. 837d.]

SEC. 6. Any capacity in Federal transmission lines connecting, either by themselves or with non-Federal lines, a generating plant in the Pacific Northwest or Canada with the other area or with any other area outside the Pacific Northwest, which is not required for the transmission of Federal energy or the energy described in section 9, shall be made available as a carrier for transmission of other electric energy between such areas. The transmission of other electric energy shall be at equitable rates determined by the Secretary, but such rates shall be subject to equitable adjustment at appropriate intervals not less frequently than once in every five years as agreed to by the parties. No contract for the transmission of non-Federal energy on a firm basis shall be affected by any increase, subsequent to the execution of such contract, in the requirements for transmission of Federal energy, the energy described in section 9, or other electric energy. [16 U.S.C. 837e.] Transmission lines.

Rates.

SEC. 7. The Secretary shall offer to amend, without imposing any other requirement as a condition to such amendment, all existing contracts for the sale or exchange of electric power generated at Federal hydroelectric plants in the Pacific Northwest to include, and shall include in all new contracts, provisions giving the purchaser priority on electric power generated at such plants in conformity with the provisions of this Act. [16 U.S.C. 837f.]

SEC. 8. No electric transmission lines or related facilities shall be constructed by any Federal agency outside the Pacific Northwest for the purpose of transmitting electric energy between the Pacific Northwest and Pacific Southwest, nor shall any arrangement for transmission capacity be executed by any Federal agency for the purpose of financing such lines and related facilities to be constructed by non-Federal entities, except those lines and facilities recommended for Federal construction in the Report of the Secretary of the Interior submitted to Congress on June 24, 1964, as supplemented on July 27, 1964, or as hereafter specifically authorized by Congress: *Provided*, That, except with respect to electric transmission lines and related facilities for the purpose of transmitting electric energy between the two regions above mentioned, nothing herein shall be construed as expanding or diminishing in any way the present authority of the Secretary of the Interior to construct transmission lines to market power and energy. [16 U.S.C. 837g.]

Applicability.

SEC. 9. The provisions of this Act shall not be applicable to (1) the Canyon Ferry project and (2), except as provided in section 6, downstream power benefits to which Canada is entitled under the treaty between Canada and the United States relating to the cooperative development of the water resources of the Columbia River Basin, signed at Washington, January 17, 1961, nor to energy or capacity disposed of to Canada in any exchange pursuant to paragraph 1 or 2 of article VIII thereof. Nothing in this Act shall be construed to modify the geographical preference of power users in the State of Montana which is established by the Hungry Horse Dam Act (Act of June 4, 1944 [So in original; should be June 5, 1944], 58 Stat. 270), as amended. [16 U.S.C. 837h.]

CITY OF RIVERSIDE

Minutes of Regular Meeting of the City Council
Date of Meeting: March 20, 1990
Time of Meeting: 9 A.M.
Place of Meeting: Council Chamber, City Hall

	COUNCILMEMBERS						
WARDS	LOVERIDGE 1	CLARKE 2	MANSFIELD 3	BUSTER 4	OSBORNE 5	THOMPSON 6	7
Present	X	X	X	X	X	X	X
Motion		X					
Second				X			
All Ayes							

Roll Call:

FIRM PEAKING CAPACITY SALE/EXCHANGE AGREEMENT WITH BONNEVILLE POWER ADMINISTRATION

A written report was submitted from the City Manager and the Public Utilities Director, concurred in by the City Attorney, recommending that the City Council authorize execution of a Firm Peaking Capacity Sale/Exchange Agreement between Bonneville Power Administration and the City of Riverside. Following discussion, the recommendation was approved as presented.

Certified under penalty of perjury to be a full, true and correct excerpt from the Minutes of the City Council appearing on Page 75-386, on file in my office.

Alice A. Hare
City Clerk of the City of Riverside

Dated this 9th day of April, 1990, at Riverside, CA.

Contract No. DE-MS79-94BP93958
05/20/94

AUTHENTICATED

1996 DIVERSITY EXCHANGE AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
RIVERSIDE, CALIFORNIA

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This 1996 DIVERSITY EXCHANGE AGREEMENT (Agreement) is executed as of July 5th 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville"), and the CITY OF RIVERSIDE, CALIFORNIA ("Riverside"), a municipal corporation of the State of California. Bonneville and Riverside are hereinafter sometimes referred to individually as "Party" and collectively as "Parties".

W I T N E S S E T H:

WHEREAS Bonneville sells electric capacity and energy at wholesale, and projects availability of amounts in excess of its existing obligations to deliver such capacity and energy to its Pacific Northwest customers; and

WHEREAS Riverside is the owner of an electric generation, transmission and distribution system which it uses to supply capacity and energy to its customers and other utilities; and

WHEREAS the Parties have entered into an agreement which, among other things, provides for the exchange of capacity for energy and for a capacity sale by Bonneville (Contract No. DE-MS79-90BP92858), and the Parties desire to enter into arrangements which provide for additional exchanges; and

WHEREAS Riverside has entered into, or intends to enter into, one or more agreements which provide for transmission service on the DC Intertie between the Nevada-Oregon border and Riverside's electric system; and

WHEREAS Riverside intends to enter into an agreement with the Southern California Edison Company (SCE) which provides for the integration of capacity and energy acquired pursuant to this Agreement (SCE-Riverside Supplemental Integration Agreement); and

WHEREAS Bonneville is authorized pursuant to law to dispose of surplus electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission

facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. EFFECTIVE DATE AND TERM

(a) **Effective Date**

Unless otherwise agreed, this Agreement shall become effective at 0001 hours on the first day of the first month after the occurrence of all the following events (Effective Date):

(1) execution of this Agreement by both Parties; and

(2) the effective date of the Transmission Service Agreement, or, if Riverside should enter into more than one Transmission Service Agreement to provide for deliveries hereunder, the latest effective date of such agreements; and

(3) the effective date of the SCE-Riverside Supplemental Integration Agreement; and

(4) April 30, 1996.

(b) **Term**

This Agreement shall remain in full force and effect until the earlier of:

(1) 2400 hours on the anniversary date twenty (20) years after the Effective Date; or

(2) the date the Transmission Service Agreement terminates, or, if Riverside has entered into more than one Transmission Service Agreement to provide for deliveries hereunder, the earliest termination date of any such agreements unless first replaced by other agreements or other suitable arrangements; or

(3) the date the Edison-Riverside Supplemental Integration Agreement terminates unless first replaced by other agreements or other suitable arrangements.

All obligations incurred hereunder prior to termination shall be preserved until satisfied.

2. DEFINITIONS

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified.

(a) "Calendar Week" means the week beginning at 0001 hours on Sunday and ending at 2400 hours on the following Saturday.

(b) "Contract Demand" means the applicable maximum hourly rate of delivery for Firm Peaking Capacity specified in section 4(a).

(c) "Contract Year" means the period beginning at 0001 hours on May 1 and ending at 2400 hours the following April 30.

(d) "DC Intertie" means the direct-current 1000 kilovolt extra high voltage electric transmission line between Bonneville's Celilo Substation, located in The Dalles, Oregon, and the Los Angeles Department of Water and Power's Sylmar Switching Station, located in Sylmar, California.

(e) "Delivery Season" means the period beginning at 0001 hours on November 1 and ending at 2400 hours on the following April 15.

(f) "Energy Account" means an account consisting of Exchange Energy, Seasonal Return Energy and Peaking Replacement Energy, the delivery of which has been deferred pursuant to section 4(d), 5(b) or 7(b).

(g) "Exchange Energy" means the energy Riverside is obligated to deliver to Bonneville in exchange for Bonneville deliveries of Firm Peaking Capacity.

(h) "Firm Peaking Capacity" means the capacity delivered by Bonneville to Riverside pursuant to this Agreement.

(i) "Firm Peaking Energy" means the energy delivered by Bonneville to Riverside associated with Bonneville's deliveries of Firm Peaking Capacity during the Summer Season and Winter Season.

(j) "Off-peak Hours" means all other hours which are not On-peak Hours as defined in section 2(k).

(k) "On-peak Hours" means the following hours:

(1) 0900 to 2300 hours Monday through Friday, excluding holidays, during the period of May 1 through October 31; and

(2) 0800 to 2200 hours Monday through Friday, excluding holidays, during the period November 1 through April 30.

(l) "Outage" means an interruption or curtailment of deliveries due to a reduction, including to zero, of available DC Intertie transmission capacity due to physical or operating limitations.

(m) "Peaking Replacement Energy" means the energy which Riverside is obligated to deliver to Bonneville, pursuant to section 5, to replace Firm Peaking Energy delivered during the Summer Season and the Winter Season.

(n) "Point of Delivery" means the point(s) where deliveries of capacity and energy between the Parties takes place pursuant to section 8.

(o) "Seasonal Firm Energy" means the energy delivered by Bonneville to Riverside associated with Bonneville's deliveries of Firm Peaking Capacity during the Spring Season.

(p) "Seasonal Return Energy" means the energy Riverside is obligated to deliver to Bonneville, pursuant to section 4(c), in exchange for Bonneville deliveries of Seasonal Firm Energy the preceding Spring Season.

(q) "Spring Season" means the period beginning at 0001 hours on May 1 and ending at 2400 hours the following June 30.

(r) "Summer Season" means the period beginning at 0001 hours on July 1 and ending at 2400 hours on the following October 31.

(s) "Total Incremental Cost" means the sum of the incremental fuel cost, incremental operation and maintenance cost, generating unit start-up cost, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Riverside in supplying Exchange Energy to Bonneville, including transmission losses incurred by Riverside in delivering Exchange Energy to the Point of Delivery, that would not otherwise have been incurred but for Bonneville's purchase of Exchange Energy pursuant to section 7(d).

(t) "Transmission Service Agreement" means any agreement entered into by Riverside and a third party whereby Riverside acquires transmission service for deliveries in accordance with this Agreement.

(u) "Uncontrollable Force" means any act or event beyond the control of a Party which adversely affects the ability of the Party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid, including, but not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning, and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage, and restraint by court order or by regulatory authorities; and, after a good faith effort by the affected Party to so obtain, action or nonaction by or failure to obtain the necessary authorizations or approvals from any governmental agency or regulatory authority.

(v) "Winter Season" means the period beginning at 0001 hours on November 1 and ending at 2400 hours on the following April 30.

(w) "Workday" means each day which both Bonneville and Riverside observe as a regular day of work.

3. EXHIBITS

Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), Bonneville's General Contract Provisions, Form PSC (SW-1) (Exhibit B), 16 U.S.C. Section 837 (1984) (Public Law 88-552) (Exhibit C), and the IPA Monthly Budget Summary for Riverside as contained in the Final Operating Budget for the Intermountain Power Project (Exhibit D) are attached hereto and hereby made a part of this Agreement. In the event a provision of Exhibit A or B conflicts with sections 1 through 18 of this Agreement, then the provisions of sections 1 through 18 of this Agreement shall control. In the event a provision in Exhibit B conflicts with a provision of Exhibit A, then the provision in Exhibit A shall control.

4. CAPACITY FOR ENERGY EXCHANGE

(a) **Contract Demand**

Bonneville shall make available to Riverside Firm Peaking Capacity each hour in an amount equal to the applicable Contract Demand.

(1) From the Effective Date through April 30, 1998, the Contract Demand during the Spring Season and Summer Season shall be fifty (50) megawatts (MW), and the Contract Demand during the Winter Season shall be thirteen (13) MW.

(2) From May 1, 1998 through the end of the term of this Agreement, the Contract Demand during the Spring Season and Summer Season shall be sixty (60) MW, and the Contract Demand during the Winter Season shall be fifteen (15) MW.

(b) **Energy Deliveries by Bonneville**

(1) During the Winter Season and Summer Season, Firm Peaking Energy shall be delivered by Bonneville pursuant to the scheduling provisions of section 9, in daily amounts, including holidays, up to six (6) megawatthours (MWh) per MW of the applicable Contract Demand, and in Calendar Week amounts up to thirty (30) MWh per MW of the applicable Contract Demand.

(2) During the Spring Season, Riverside shall be obligated to schedule Seasonal Firm Energy as follows, unless otherwise agreed by the Parties' schedulers or dispatchers:

(A) From the Effective Date through April 30, 1998, fifty (50) MW for six (6) hours during each weekday, and fifteen (15) MW for each remaining hour during such season; and

(B) After April 30, 1998, sixty (60) MW for six (6) hours during each weekday, and eighteen (18) MW for each remaining hour during such season.

(c) **Energy Deliveries by Riverside**

(1) Riverside shall, in return for Firm Peaking Capacity made available during the current Contract Year and Seasonal Firm Energy delivered by Bonneville during the preceding Spring Season, deliver Exchange Energy and Seasonal Return Energy to Bonneville each Delivery Season as provided herein.

(A) The amount of Exchange Energy provided shall equal the exchange ratio in MWh/MW multiplied by the applicable Contract Demand during each month of the Summer Season and the Winter Season. The exchange ratio shall be one hundred and ninety five (195) MWh/MW per month.

(B) The amount of Seasonal Return Energy shall equal the amount of Seasonal Firm Energy delivered during the previous Spring Season.

(2) Exchange Energy and Seasonal Return Energy shall be delivered during Off-peak Hours in equal weekly increments during the Delivery Season, unless otherwise agreed by the Parties' schedulers or dispatchers.

(3) During the period of September 1 through October 31 of each Contract Year, Riverside may predeliver Exchange Energy and Seasonal Return Energy in amounts agreed to by the Parties. Any such predeliveries shall be at times and at rates of delivery agreed to by the Parties' schedulers and/or dispatchers. Riverside may also predeliver Exchange Energy and Seasonal Return Energy during the Delivery Season in amounts agreed to by the Parties. Any Exchange Energy and/or Seasonal Return Energy delivered during times, or in amounts, other than as provided in section 4(c)(2) shall only serve to reduce the length of the Delivery Season and shall not reduce the weekly amount of such energy Riverside would otherwise deliver.

(d) **Exchange Energy and Seasonal Return Energy Delivery Limitations**

(1) Unless otherwise agreed, the maximum hourly rate of delivery for Exchange Energy and Seasonal Return Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, shall equal the maximum Contract Demand during the current Contract Year.

Upon agreement of the Parties' schedulers, and subject to Riverside making arrangements for additional intertie capacity or counter-scheduling against a Bonneville delivery to Riverside:

(A) during the months of November, December, January, and February, the maximum hourly rate of delivery for Exchange Energy and Seasonal Return Energy, when combined with

other deliveries by Riverside to Bonneville under this Agreement, shall be two hundred percent (200%) of the maximum Contract Demand for the current Contract Year; and

(B) during the months of March and April, the maximum hourly rate of delivery for Exchange Energy and Seasonal Return Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, shall be one hundred thirty percent (130%) of the maximum Contract Demand for the current Contract Year.

(2) Subject to Outages, and unless limited by Bonneville pursuant to sections 4(d)(3) and 4(d)(4), Riverside shall complete each Calendar Week's obligation to deliver Exchange Energy and Seasonal Return Energy by the end of such Calendar Week.

(3) At the time schedules for the delivery of Exchange Energy and Seasonal Return Energy are established by Riverside pursuant to section 9, Bonneville may limit the hourly delivery rate for Exchange Energy and Seasonal Return Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, to not less than sixty percent (60%) of the maximum Contract Demand for the current Contract Year.

(4) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Exchange Energy and Seasonal Return Energy, including down to zero (0).

(5) To the extent that Bonneville restricts the delivery of Exchange Energy and/or Seasonal Return Energy,

(A) Bonneville may place such energy into the Energy Account provided for in section 6; or

(B) the Parties may mutually agree to delay the delivery of such energy.

5. PEAKING REPLACEMENT ENERGY

(a) **Obligation to Deliver**

Subject to sections 5(b) and 7(b), Riverside shall deliver Peaking Replacement Energy to Bonneville each day in an amount equal to the amount of Firm Peaking Energy delivered by Bonneville the preceding day. Unless otherwise agreed by the Parties' schedulers and dispatchers, deliveries of Peaking Replacement Energy shall be limited to Off-peak Hours.

(b) **Peaking Replacement Delivery Limitations**

(1) Unless otherwise agreed, the maximum hourly rate of delivery of Peaking Replacement Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, shall be equal to the maximum Contract Demand for the current Contract Year.

(2) At the time schedules for the delivery of Peaking Replacement Energy are established by Riverside pursuant to section 9, Bonneville may limit the hourly delivery rate for Peaking Replacement Energy to not less than sixty percent (60%) of the maximum Contract Demand for the current Contract Year, rounded to the nearest whole megawatt.

(3) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Peaking Replacement Energy, including down to zero (0).

(4) To the extent that Bonneville restricts the delivery of Peaking Replacement Energy,

(A) Bonneville may place such energy into the Energy Account provided for in section 6; or

(B) the Parties may agree to delay the delivery of such energy.

6. ENERGY ACCOUNT

(a) Upon the Effective Date of this Agreement, an Energy Account will be established and maintained by Bonneville which shall contain the deferred amounts of Peaking Replacement Energy, Exchange Energy and Seasonal Return Energy credited to such account pursuant to this Agreement.

(b) Subject to this section 6(b), Bonneville may withdraw energy from the Energy Account during a Calendar Week by providing Riverside with notice by 1400 hours on the Thursday prior to such Calendar Week, specifying the weekly quantity of energy to be withdrawn, and the rate(s) of delivery for such energy.

(1) Unless otherwise mutually agreed, the rate(s) of delivery shall not exceed the maximum Contract Demand for the current Contract Year, and the times of delivery shall be Off-peak Hours.

(2) Such withdrawals shall not cause Riverside to defer or otherwise limit deliveries of Exchange Energy, Seasonal Return Energy or Peaking Replacement Energy. Riverside shall deliver energy as requested pursuant to this section 6(b) during the Delivery Season from the Energy Account, subject to Outages. Withdrawals from the Energy Account at times other than during the Delivery Season shall be by agreement of the Parties' schedulers.

(3) After April 15, and at Bonneville's request, the Parties shall attempt in good faith to develop a mutually agreeable plan for the delivery of any energy remaining in the Energy Account. If the Parties are unable to agree on a plan, and such energy is not delivered by the following September 30, the energy shall be cashed out pursuant to section 6(c).

(c) Each October 1, energy remaining in the Energy Account shall be cashed-out. The cash-out price for such energy shall be the lesser of (1) Bonneville's contract rate specified in Bonneville's then effective nonfirm rate schedule or (2) the average incremental energy rate paid by Riverside for energy from the Intermountain Power Project, which shall be adjusted by increasing the rate twelve and three-tenths percent (12.3%), during the previous Delivery Season, as specified in Exhibit D. Riverside shall be relieved of any obligation to provide energy to Bonneville to the extent the energy is cashed out.

Riverside shall provide Bonneville with a copy of the IPA Monthly Budget Summary for each fiscal year no later than October 1 of each year. The new IPA Monthly Budget Summary shall be attached to this Agreement as a revised Exhibit D, and shall be applicable to the next Delivery Season. Riverside shall mail the revised IPA Monthly Budget Summary to:

Chief, Interchange Scheduling Section - PSKI
United States Department of Energy
Bonneville Power Administration
P.0. Box 3621
Portland, OR 97208-3621

7. TRANSMISSION LIMITATIONS

(a) In the event of an interruption of deliveries by either Party due to an Outage, transactions under this Agreement will have priority over any competing nonfirm energy transaction of Riverside and Bonneville.

(b) Following periods of an Outage, Riverside shall continue to be obligated to deliver Exchange Energy, Seasonal Return Energy and Peaking Replacement Energy. Both Parties shall use best efforts to reschedule interrupted or curtailed deliveries of such energy under conditions approximately equivalent to the conditions existing prior to the Outage; **provided**, that in rescheduling such energy, Riverside shall not exceed the delivery limits set forth in sections 4(d) and 5(b), unless otherwise agreed. The Parties may also agree to reschedule delivery at other times and under conditions other

than those existing prior to the Outage. To the extent the Parties have not rescheduled such energy within sixty (60) days following the end of the Outage, the Energy Account shall be credited for any such amounts of energy.

(c) **Exchange Energy Relief**

If during any month the availability of Firm Peaking Energy during On-peak Hours is less than eighty-five percent (85%) due to one or more Outages, Riverside shall be excused from delivering an amount of Exchange Energy determined by subtracting the actual percentage of Firm Peaking Energy availability during the On-peak Hours from eighty-five percent (85%), and multiplying the result by the quantity of Exchange Energy Riverside would otherwise deliver for Firm Peaking Capacity made available during such month; **provided**, that Bonneville may elect to purchase, pursuant to section 7(d), Exchange Energy which Riverside would otherwise be excused from delivering pursuant to this section 7(c).

(1) Riverside shall notify Bonneville and request a reduction in Riverside's Exchange Energy obligation when such reduction is warranted pursuant to this section.

(2) Any reduction in Riverside's Exchange Energy obligation shall be met by decreasing the length of the Delivery Season rather than adjusting the weekly amounts of Exchange Energy to be delivered by Riverside.

(3) If Riverside delivers to Bonneville more than its Exchange Energy obligation for any Contract Year, Riverside may elect to:

(A) reduce its Exchange Energy obligation for the next Contract Year; or

(B) use such energy to reduce its Peaking Replacement Energy obligations at times and rates of delivery agreed to by the Parties' schedulers or dispatchers; or

(C) if agreed to by Bonneville, cashout such energy at the rate determined pursuant to section 6(c).

(d) **Bonneville Purchase of Exchange Energy**

Bonneville may elect to purchase Exchange Energy which Riverside otherwise would be excused from delivering pursuant to section 7(c) as follows:

(1) Bonneville shall notify Riverside at least one (1) month prior to requesting delivery of such Exchange Energy.

(2) Within ten (10) Workdays after receipt of Bonneville's notice requesting Exchange Energy, and prior to Riverside committing to obtain energy with which to supply Exchange Energy, Riverside shall inform Bonneville of the probable lowest cost resources available to supply such requested Exchange Energy, including the estimated Total Incremental Cost of such resources. If conditions change substantially, Riverside shall revise the estimated Total Incremental Cost.

(3) Bonneville shall provide Riverside with at least one (1) Calendar Week's final written notice prior to the start of each Calendar Week's deliveries whether Bonneville shall require Riverside to deliver the Exchange Energy, or whether Bonneville relieves Riverside of the obligation to deliver that Calendar Week's Exchange Energy.

(4) For all deliveries of Exchange Energy pursuant to this section 7(d), Bonneville shall pay Riverside the Total Incremental Cost of the Exchange Energy for the first three (3) months of deliveries, and one hundred fifteen percent (115%) of Riverside's Total Incremental Cost for all Exchange Energy delivered after three (3) months pursuant to this section 7(d).

8. POINTS OF DELIVERY

Deliveries shall be at the point where the DC Intertie crosses the Nevada-Oregon border, or the point(s) where the 500 kV alternating current transmission line(s)

between Oregon and California cross the California-Oregon border, or at such other points as agreed by the Parties.

9. SCHEDULING PROVISIONS

Submission of all schedules between Bonneville and Riverside, or its agent, for delivery of capacity and energy hereunder shall be subject to the following provisions unless otherwise agreed by the Parties' schedulers or dispatchers, or their agents as designated by a Party to act on its behalf:

(a) Preschedules shall be completed by 0930 hours on each Workday and shall be effective for each hour of the following day, or days, through the next Workday. Each Party, or its agent shall endeavor to avoid requesting changes in prearranged schedules. Changes in preschedules shall be submitted no later than thirty (30) minutes before the hour, for which the change is to be effective, emergencies excepted.

(b) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts of Firm Peaking Energy or Seasonal Firm Energy that Riverside, or its agent, anticipates it will schedule from Bonneville each day for the following ten (10) days. Riverside, or its agent, shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Riverside, or its agent, or Bonneville to schedule such amounts.

10. PAYMENT

Each Party shall pay the other Party in accordance with this Agreement upon receipt of properly documented bills. Bills submitted by Riverside must reference this contract number and be sent to:

United States Department of Energy
Bonneville Power Administration
Chief, Program and Contracts Review Section - DSAC
P.O. Box 3621
Portland, OR 97208-3621

Bills submitted by Bonneville must reference this contract number and be sent to:

City of Riverside
Central Cashiering
3900 Main Street
Riverside, CA 92522

All payments shall be rendered by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than its mailing date. Should the twentieth (20th) day be a Saturday, Sunday, or holiday, then the due date shall be the next following business day. Payment of bills shall be in accordance with Exhibits A and B, attached hereto.

11. UNCONTROLLABLE FORCES

(a) Obligations of the Parties, other than those to pay money under section 10, shall be excused when failure to perform such obligations is due to an Uncontrollable Force; provided, however, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability with reasonable dispatch. Nothing in this section 11 shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(b) Each Party shall notify the other as soon as possible of any Uncontrollable Force which may adversely affect performance under this Agreement. Failure of a Party to give notice to the other Party shall not be deemed a waiver of such Uncontrollable Force.

(c) For purposes of this section 11, an Outage of less than one (1) year shall not be considered an Uncontrollable Force.

12. ASSIGNMENT OF AGREEMENT

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

13. NOTICES

Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in

writing and shall be deemed properly served, given, or made if delivered in person or sent by telegraph, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:

To Riverside:	Public Utilities Director City of Riverside 3900 Main Street Riverside, CA 92522
To Bonneville:	Assistant Administrator for Power Sales - P United States Department of Energy Bonneville Power Administration P.0. Box 3621 Portland, OR 97208-3621

Either Party may, by written notice to the other Party, change the designation or address of the person so specified as the one to receive notices pursuant to this Agreement.

14. DISPUTES

Pending resolution of any disputed matter, the Parties shall continue performance of their respective obligations pursuant to this Agreement. The Parties shall discuss disputes regarding any matter relating to this Agreement, and shall use their best efforts to amicably and promptly resolve each such dispute.

15. AUDITS

Each Party shall have the right to audit and to examine any cost, payment, settlement or supporting documentation, including, but not limited to, audit reports, resulting from any items set forth in this Agreement. Any such audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The Party being audited shall cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of five (5) years following the first billing for such cost under this Agreement. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period.

The Party being audited shall be notified in writing of any exception taken as a result of an audit promptly after completion of the audit. The Party being audited shall have thirty (30) days to review the notice of exception.

(a) If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) to the other Party, with interest calculated in the same manner as in Exhibits A and B, or their successors, within ten (10) days after agreement is reached.

(b) If the Parties dispute any exception(s) taken as a result of the audit, the owing Party shall so notify the other Party in writing promptly after its receipt of the written notification of exception. Such dispute shall then be subject to the provisions set forth in section 14. If upon resolution of the dispute, it is determined that a Party shall make payment to the other Party, such payment shall be made within ten (10) days of resolution of the dispute, with interest calculated in the same manner as set forth in Exhibits A and B, or their successors.

16. GOVERNING LAW

This Agreement shall be interpreted, governed by and construed under Federal law applicable to Bonneville.

17. WAIVERS

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement shall be waived except in writing. Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter.

18. SIGNATURE CLAUSE

The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ WALTER E. POLLOCK
Assistant Administrator
for Power Sales

Name Walter E. Pollock
(Print / Type)

Date August 12, 1994

CITY OF RIVERSIDE, CALIFORNIA

By /S/ JOHN E. HOLMES

Name John Holmes
(Print / Type)

Title City Manager

Date July 5, 1994

(PMLAN-PMCN-W:\PMC\CT\93958\93958.DOC)

TMC QA Contracts Documentation Checklist Procedure

NOTE: It's the Contract Specialist's (CS) responsibility to double-check their work as it is finalized. The Quality Assurance Team (QA) is reviewing documents as a final independent check for accurate content and technical validity prior to the contract action documents being handed to TM for signature. It is not intended to replace the CS' own accuracy check.

The CS initiates the QA Checklist. It should be submitted to the QA Team member **TWO** (2) days in advance of the desired signature date, together with the required supporting documents. Documents should be submitted in **FINALIZED** condition for review. If an item is not relevant, write "N/A". If there are multiple OASIS Request Queue and/or AREF numbers, include them all. Attach a copy of the OASIS 'Flat File' posting for all referenced Request #s. ***Customer Response Deadline***: If the document is governed by a Tariff response deadline, write in the date of that deadline. ***Documentation creation process*** **- From Template/Re-edit -** any document that is **NOT** created ***directly*** from a template is considered a re-edit

Step 1: CS checks (✓) each line as it is completed. Use N/A as appropriate. If OGC review is required, this should be complete ***PRIOR TO*** submission to QA and supporting documentation attached. CS must ensure that contract action has required authorization and sign-off prior to implementation. **NOTE**: Some line items require the attachment of supporting documentation.

Step 2 and 3: TCMS Group completes a review of the contract document and cover letter. The TCMS Group must certify that the documents are formatted consistent with BPA and TBL guidelines, are free from errors and omissions, meet BPA's Records Management policies, and are processed in a manner consistent with BPA and TBL guidance (policies, procedures, and practices).

Step 4: QA Team member certifies that all information provided by the CS is accurate.

AUTHENTICATED

Contract No. DE-MS79-94BP93658
03/14/94

CAPACITY FOR ENERGY EXCHANGE AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
THE CITY OF PASADENA

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This CAPACITY FOR ENERGY EXCHANGE AGREEMENT, executed as of **JUNE 29th**, 19**94**, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and the CITY OF PASADENA, CALIFORNIA (Pasadena), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

WITNESSETH:

WHEREAS Pasadena is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Pasadena, the City of Burbank (Burbank), the City of Glendale (Glendale), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which provided, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Pasadena, Burbank, and Glendale; and

WHEREAS on January 28, 1988, Pasadena and Bonneville executed Contract No. DE-MS79-87BP92413 (Sale and Exchange Agreement) which provides, among other things, for a power sale by Bonneville to Pasadena that converts to a capacity for energy exchange pursuant to certain terms and conditions; and

WHEREAS this Agreement, the Sale and Exchange Agreement, and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Bonneville and Pasadena have agreed to enter into a seasonal capacity for energy exchange under the terms and conditions set forth herein; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. TERM

This Agreement, when executed, shall become effective at 0001 hours on May 1, 1995, and shall continue in effect until 2400 hours on April 30, 2015, **provided, however**, that either Party may terminate this Agreement effective any time after May 1, 2004, by providing the other Party with four (4) years' written notice. Notwithstanding the foregoing, this Agreement shall not become effective

until the Pacific Northwest-Pacific Southwest DC Intertie transmission facilities, including the Sylmar Converter Station, are restored to full transfer capability (north to south and south to north), unless otherwise mutually agreed by the Parties. All obligations incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

(a) "Agreement" means this capacity for energy exchange agreement between Bonneville and Pasadena, Contract No. DE-MS79-94BP93658.

(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

(c) "Contract Demand" means the maximum hourly rate of delivery for capacity service. This amount is equal to 15 MW.

(d) "Contract Year" means the year beginning at 2400 hours on April 30 and ending at 2400 hours on the following April 30.

(e) "Exchange Energy" means the energy Pasadena is obligated to deliver to Bonneville during each September through March 15 period in exchange for capacity service made available by Bonneville during the preceding May through September period.

(f) "Heavy Load Hours (HLH)" means all hours other than LLH.

(g) "Light Load Hours (LLH)" means the first eight (8) hours and the last two (2) hours daily, Monday through Saturday, and all hours on Sunday.

(h) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie (Intertie) transmission lines cross the Nevada-Oregon border.

(i) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Pasadena.

(j) "Peaking Replacement Energy" means an amount of energy which Pasadena is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

(k) "Prudent Utility Practice" means those practices, methods, and equipment, including provisions for contingencies and reserves, that are commonly used to plan and operate electric power facilities reliably and safely to serve a utility's customers dependably and economically, with due regard for the state of the art in the electric power industry as practiced by major electric utilities which are members of the Western Systems Coordinating Council or successor organization.

(l) "Uncontrollable Force" means any act or event beyond the control of a Party which impairs the ability of the party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid. Uncontrollable Force includes, but it is not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning and other natural catastrophes, epidemic, war, riots, labor or material shortage, strike or labor dispute, or sabotage; and also includes restraint by an order of a court of competent jurisdiction or by regulatory authorities, against an action taken or not taken by a Party, after a good faith effort by the appropriate Party (1) to obtain relief from such order, or (2) to obtain any necessary authorizations or approvals from any governmental agency or regulatory authority.

(m) "Workday" means each day which both Bonneville and Pasadena observe as a regular day of work.

3. EXHIBITS

Exhibit A (GCP Form PSC(SW)-1, dated 11/3/83) is attached hereto and hereby made a part of this Agreement. In the event of a conflict between the body of this Agreement and Exhibit A, the body of this Agreement shall prevail.

4. SERVICE TO PASADENA

(a) **Service to Pasadena During May and June**

During the months of May and June, Bonneville shall make Peaking Energy available to Pasadena. Pasadena may preschedule such Peaking Energy at an hourly rate of delivery not to exceed 15 MW during any hour. Pasadena shall schedule no less than 1,630 MWh during the month of May, and no less than 1,630 MWh during the month of June. Pasadena shall not deliver any Peaking Replacement Energy to Bonneville during this period, but shall return such energy during the following September through March 15 period, as provided for in section 5 below.

(b) **Service to Pasadena During July, August, and September**

(1) **Deliveries of Peaking Energy by Bonneville**

Bonneville shall deliver Peaking Energy to Pasadena during each July, August, and September in amounts not to exceed 15 MWh during any hour, and not to exceed 150 MWh during any day. Peaking Energy shall be delivered in Calendar Week amounts not to exceed 750 MWh during any week.

(2) **Deliveries of Peaking Replacement Energy by Pasadena**

Pasadena shall deliver Peaking Replacement Energy to Bonneville in an amount equal to the amount of Peaking Energy delivered to Pasadena. Such Peaking Replacement Energy shall be delivered by 2400 hours on the day following Bonneville's delivery of such Peaking Energy, at a rate of delivery not to exceed 15 MW during any hour, unless otherwise agreed to by the Parties.

(3) Hourly deliveries of Peaking Replacement Energy by Pasadena during July, August, and September shall be considered nonfirm by both Parties. For the purposes of this Agreement, "nonfirm" means that the schedule may be reduced with an oral notice by either Party at least thirty minutes prior to the start of the hour of the reduction. Deliveries reduced under this section shall be rescheduled at times and rates as agreed to by the Parties.

(4) All Peaking Replacement Energy will be prescheduled pursuant to section 6.

5. SERVICE TO BONNEVILLE

(a) Service to Bonneville During the September Through March 15 Period

(1) Exchange Energy

In exchange for capacity service made available by Bonneville during May through September, Pasadena shall deliver to Bonneville during LLH, unless otherwise agreed, and subject to adjustment pursuant to section 8(d), an amount of Exchange Energy equal to:

Delivery Period	Exchange Energy Obligation
September 1 through March 15	16,500 MWh

(2) May-June Peaking Replacement Energy

In addition to the Exchange Energy obligation described in section 5(a)(1), Pasadena shall deliver to Bonneville during LLH, unless otherwise agreed, and subject to adjustment pursuant to section 8(c), a minimum amount of Peaking Replacement Energy equal to:

Delivery Period	Peaking Replacement Energy Obligation
September 1 through March 14	3,260 MWh (minimum)

To the extent that Pasadena schedules amounts greater than the 3,260 MWh minimum during any May-June period, the 3,260 MWh shall be increased to reflect such additional amounts of Peaking Replacement Energy.

(b) **Rate of Delivery**

The rate of delivery for Exchange Energy and Peaking Replacement Energy, individually or in combination, pursuant to sections 4(b)(2), 5(a)(1), and 5(a)(2) shall be as mutually agreed by the Parties. Except as provided in section 5(c), Bonneville shall accept such energy as scheduled by Pasadena at the mutually agreed upon rate of delivery, and such rate shall not be less than 15 MW when scheduled.

(c) Exchange Energy deliveries, pursuant to section 5(a), shall be considered firm by the Parties for the September through March 15 period. Such energy is to be firm for such period, however, it is "nonfirm" on any hour, as "nonfirm" is described in section 4(b)(3). For the purposes of this section 5(c) "firm" means that the Parties shall use best efforts to deliver all Exchange Energy by March 15 of each year. Deliveries that are curtailed shall be rescheduled at times and rates as agreed to by the Parties.

(d) All Exchange Energy will be prescheduled pursuant to section 6.

6. SCHEDULING PROVISIONS

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

(b) Hourly preschedules shall be submitted by 0930 hours.

(c) By 1200 hours on any Wednesday, Bonneville may request estimates of the hourly amounts that Pasadena anticipates it will schedule from Bonneville each day for the following five (5) days. Pasadena shall submit such estimates to Bonneville by 1200 hours on the first Workday following Bonneville's request. Such estimates are for the purpose of information only and shall not obligate either Pasadena or Bonneville to schedule such amounts.

(d) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such requested changes shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

7. FORCE OUT ENERGY

If by 2400 hours on the 15th day of March each year Pasadena has been unable to deliver all Exchange Energy and/or Peaking Replacement Energy which Pasadena is obligated to return under section 5(a), or Bonneville has been unable to receive such energy, then Pasadena shall preschedule the energy balance (Force Out Energy) for delivery during LLH beginning at 2400 hours on the 15th day of March until the balance of such Force Out Energy due to be delivered by Pasadena to Bonneville is zero.

Unless otherwise mutually agreed, the minimum rate of delivery for Force Out Energy shall be 15 MW until the remaining balance is less than 15 MWh. Such remaining balance shall be delivered on the next LLH.

Deliveries of Force Out Energy shall be considered firm by both Parties.

8. TRANSMISSION LIMITATIONS

(a) **Peaking Energy Curtailments**

At any time, Bonneville may curtail deliveries of Peaking Energy for necessary maintenance, or to protect Bonneville's system during operational constraints beyond its reasonable control due to unexpected instability or thermal limitation for equipment or line outages, disturbances on the Federal Columbia River Transmission System (FCRTS), disturbances on the system of an interconnected utility, or other unexpected adverse system conditions. To the extent any line limitation due to forced outage or forced capacity reduction of the Intertie precludes Bonneville from delivering Peaking Energy, Bonneville shall be relieved of its obligation to deliver the Peaking Energy during the period of the above conditions or line limitations.

(b) **Exchange Energy or Peaking Replacement Energy Curtailments**

If Pasadena is unable to deliver, or Bonneville is unable to accept, scheduled Peaking Replacement Energy or Exchange Energy due to any necessary maintenance or cause which is beyond their reasonable control, including transmission or generation limitations, delivery of energy shall be curtailed to the extent necessary until such cause has been removed or ends. Deliveries reduced under this section 8(b) shall be rescheduled pursuant to section 6 at such times and rates as agreed by the Parties.

(c) **Peaking Replacement Energy Relief**

If during any May or June Pasadena is unable to receive the minimum Peaking Energy specified in section 4(a) due to transmission outages, then Pasadena shall be excused from delivering an amount of Peaking Replacement Energy equal to 3,260 MWh less the amount received.

(d) **Exchange Energy Relief**

If during any month Pasadena is unable to receive at least eighty-five percent (85%) of the Peaking Energy specified in section 4(b)(1) due to one or more transmission outages, Pasadena shall be excused from delivering an amount of Exchange Energy determined by subtracting the actual percentage of Peaking Energy delivered during the HLH from eighty-five percent (85%), and multiplying the result by 3,300 MWh (one-fifth of 16,500 MWh), which is equal to the quantity of Exchange Energy Pasadena would otherwise deliver for Peaking Capacity made available during such month.

(e) Pasadena shall notify Bonneville and request a reduction in either Pasadena's Exchange Energy obligation or Peaking Replacement Energy obligation, when such reduction is warranted pursuant to this section.

(f) **Order of Precedence**

The Parties shall curtail pro rata on an hourly basis all agreements executed on or before July 1, 1993, for firm energy or capacity, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over agreements executed after July 1, 1993, for

firm energy or capacity. Deliveries pursuant to this Agreement shall have precedence over all nonfirm transactions.

9. POINTS OF DELIVERY

The point of delivery for all deliveries pursuant to this Agreement is NOB, unless otherwise mutually agreed to by the Parties.

10. UNCONTROLLABLE FORCE

(a) **Obligations of the Parties**

Except as provided in section 8, obligations of the Parties shall be excused when failure to perform such obligations is due to an Uncontrollable Force; **provided, however**, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability in a timely manner. Nothing in this section 10(a) shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(b) **Notice**

Each Party shall notify the other as soon as possible of any Uncontrollable Force which may impair performance under this Agreement. Failure to give notice shall not be deemed a waiver of such Uncontrollable Force.

11. ASSIGNMENT OF AGREEMENT

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

12. NOTICES

(a) Unless this Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given, or made if delivered in person or sent by telegraph, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:

To Pasadena:

General Manager
City of Pasadena
Water and Power Dept.
150 S. Los Robles Ave., Suite 200
Pasadena, CA 91101

To Bonneville:

Assistant Administrator for Power Sales - P
United States Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

(b) Either Party may, by written notice to the other Party, change the designations or address of the person so specified as the one to receive notices pursuant to this Agreement.

13. DISPUTES

Pending resolution of a disputed matter, the Parties shall continue performance of their respective obligations pursuant to this Agreement. For a period not to exceed 6 months unless otherwise mutually agreed, the Parties shall discuss disputes regarding any matter relating to this Agreement, and shall use their best efforts to amicably and promptly resolve each such dispute. If the Parties have been unable to resolve a disputed matter as specified above, then each Party has the right to adopt any other remedies available under law.

14. GOVERNING LAW

This Agreement shall be interpreted, governed by, and construed under Federal law.

15. WAIVERS

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement may be waived except as documented or confirmed in writing. Any waiver at any time by a Party of its right with respect to a default under this Agreement, or with any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter. Either Party may waive any notice or agree to accept a shorter notice than specified in this Agreement. Such waiver of notice or acceptance of shorter notice by a Party at any

time regarding a notice shall not be considered a waiver with respect to any subsequent notice required under this Agreement.

16. SIGNATURE CLAUSE

`Each Party hereto represents that it has the authority to execute this Agreement and that it has been duly authorized to enter into this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By **/S/ WALTER E. POLLOCK**
Assistant Administrator
for Power Sales

Name **Walter E. Pollock**
(*Print/Type*)

Date **June 29, 1994**

CITY OF PASADENA, CALIFORNIA

By **/S/ EDMUND F. SOTELO**

Name **Edmund F. Sotelo**
(*Print/Type*)

Title **Interim General Manager**
Water and Power development

Date **6/9/94**

(PMLAN-PMC-W:\PMC\CT\93658\93658.DOC)

Dated: **6/22/94**

Attest: **/S/ VIVIAN LEE STEWART**

APPROVED AS TO FORM
This 1 day Of June, 1994
By N Rasmussen
Assistant General Counsel

Service Agreement No. 00TX-10286

AUTHENTICATED

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
CORAL POWER L. L. C

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Exhibit (Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit B (Facilities Charges)
Exhibit C (Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 2nd day of February , 2000 by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and Coral Power L. L. C. (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 TERMS AND CONDITIONS

BPA agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Services (PTP Transmission Service) in accordance with the provisions of this Service Agreement and the Open Access Transmission Tariff (Tariff). The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference. BPA may change the terms and conditions of

the Tariff upon, and only upon, a determination by the Federal Energy Regulatory Commission (Commission) that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 STATEMENT OF SPECIFICATION FOR LONG-TERM FIRM TRANSMISSION SERVICE

The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit A and made applicable to that transaction.

1.3 WHOLESALE POWER AND TRANSMISSION RATES SCHEDULES

BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated by this reference.

1.4 FACILITIES CHARGES

All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit B.

1.5 ANCILLARY SERVICES

The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit C.

1.6 TRANSMISSION SCHEDULING PROVISIONS

The Transmission Customer shall schedule transmission transactions in accordance with BPA's Transmission Scheduling Provisions and Procedures as posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPAT

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 2400 hours on December 31, 1999. Service under this Service Agreement shall terminate at 2400 hours on December 31, 2004. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 CHARGES FOR TRANSMISSION SERVICE
The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the BPA Wholesale Power and Transmission Rate Schedules.

4.2 BILLING AND PAYMENT
Bills for all services provided under this Service Agreement shall be payable in accordance with the Tariff.

4.3 BPA APPROPRIATIONS REFINANCING ACT, PUBLIC LAW 104-134
The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT
Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If to Coral Power, L. L. C

Coral Power L. L. C
909 Fannin, Suite 700
Houston, TX 77010
Attention: Ms. Diane Davis
Senior Contract Administrator
Phone: (713) 767-5313
Fax: (713) 265-5313

If to BPA

Bonneville Power Administration
P. O. Box 491
Vancouver, WA 98666-0491
Attention:
Transmission Account Executive for:
Coral Power, L. L. C
Phone: (360) 418-8285
Fax: (360) 418-8320

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified transmission service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within forty-five (45) days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 INTERCONNECTION WITH OTHER SYSTEMS

Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 GOVERNING LAW

This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3. AMENDMENTS

Except as provided in Articles 1.1, 6.4 and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 TARIFF REVISIONS

In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than sixty (60) days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within thirty (30) days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then

approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within thirty (30) days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the transmission service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.4 REVISION OF EXHIBITS

If any changes to Exhibits A, B, or C are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.4.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit A pursuant to this Service Agreement, BPA shall prepare a revised Exhibit A. BPA reserves the unilateral right to amend contiguous point of delivery provisions in Exhibit A of this Service Agreement.

6.4.2 If the Parties agree to change Exhibit B, BPA shall prepare a new Exhibit B. BPA reserves the right to revise Exhibit B annually to reflect changes consistent with the provisions of Exhibit B, section 1.

6.4.3 If the Parties agree to change Exhibit C, BPA shall prepare a new Exhibit C. BPA reserves the right to update the loss factors identified in Exhibit C, section 2, Transmission Loss Factors.

6.5 TEMPORARY LOAD SHIFTS AND MAINTENANCE NOTIFICATION

The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within four (4) days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The point of contact for each Party will be designated pursuant to Article 5.2 of this

Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within four (4) days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.6 SEVERABILITY

In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.7 COMPUTATION OF TIME

To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.8 NO THIRD PARTY BENEFICIARIES

This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.9 WAIVERS

Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.10 SUCCESSORS AND ASSIGNS

This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.11 SERVICE AGREEMENT GOVERNS

In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.12 ENTIRE AGREEMENT

This Service Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

ARTICLE 7
SIGNATURES

The signatories represent that they are authorized to enter into this Service Agreement on behalf of the Party for who they sign.

CORAL POWER, L. L. C		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	**/S/ Jeffrey F. Beicker**	By:	**/S/ S. J. Long**
Name: *(Print/Type)*	**Jeffrey F. Beicker**	Name: *(Print/Type)*	Sally J. Long
Title:	**Vice President**	Title:	Transmission Account Executive
Date:	**02/09/2000**	Date:	**12-21-1999**

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EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR
LONG-TERM FIRM TRANSMISSION SERVICE

Long-Term service has not been requested at this time under this Service Agreement

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EXHIBIT B
FACILITIES CHARGES

Facilities Charges are not required at this time for service under this Service Agreement.

EXHIBIT C
ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL [1])	00TX-10286
(b)	**Energy Imbalance**	N/A	
(c)	**Control Area Reserves for Resources**	N/A	
(d)	**Control Area Reserves for Interruptible Purchases**	N/A	
(e)	**Load Regulation**	N/A	
(f)	**Reactive Supply and Voltage Control**	BPA(TBL)	00TX-10286
(g)	**Transmission Losses**	BPA(TBL)	00TX-10286

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) **Transmission Losses Associated with Federal Power**
Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) **Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power**
The Transmission Customer shall compensate BPA for losses BPA incurs when providing transmission service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be determined by multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in section 2; and

[1] BPA's Transmission Business Line.

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) Transmission Losses Associated with Delivery Facilities
Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year [2], pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) Notification

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer shall choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice for compensating BPA for transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission

[2] Fiscal Year is defined as the twelve-month period from October 1 through September 30.

Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit C.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate in the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) **Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year** The Transmission Customer has elected to purchase Transmission Losses, pursuant to the APS-96 rate schedule, at a rate of 22.80 mills per kWh for the period 2400 hours December 31, 1999, through 2400 hours September 30, 2000.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit C as appropriate, but not more frequently than once in a twelve-month (12) period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit C incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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AUTHENTICATED

Amendment No. 1
Agreement No. 00TX-10286

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

CORAL POWER, L.L.C.

This AMENDMENT to the Point-to-Point Transmission Agreement, Contract Number 00TX-10286 (Agreement), is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Transmission Provider) and Coral Power, L.L.C. (Transmission Customer). The Transmission Provider and the Transmission Customer are sometimes referred to individually as "Party", and collectively as "Parties," as the context suggests below.

This Amendment to the Agreement between the Transmission Provider and the Transmission Customer acknowledges the Parties' desire to extend the term of the Service Agreement to 0000 hours on January 1, 2010. The Parties agree that all other terms and conditions of the Agreement, as amended, remain the same.

The Transmission Provider and the Transmission Customer agree:

1. **EFFECTIVE DATE**
   This Amendment shall take effect on the date executed by the Parties (Effective Date).

2. **AMENDMENT OF AGREEMENT**

   The Transmission Provider and the Transmission Customer wish to amend the Agreement by deleting Article 3, Term of Service Agreement, and Article 5, NOTICES, and replacing them with the following:

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 0000 hours on the Effective Date and terminate at 0000 hours on January 1, 2010. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 5.2 below), shall be in writing and shall be deemed to have been received if delivered in person, by First Class mail, by telefax or sent by acknowledged delivery.

If to the Transmission Customer:

Coral Power, L.L.C.
909 Fannin, Suite 700
Houston, TX 77010
Attention: Ms. Diane Davis
Title: Senior Contract Administrator
Phone: (713) 767-5313
Fax: (713) 265-5313

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409
Attention: Transmission Account Executive for Coral Power, L.L.C.– TM/OPP2
Phone: (360) 619-6011
Fax: (360) 619-6940

By Overnight Delivery

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409
Attention: Transmission Account Executive for Coral Power, L.L.C.– TM/OPP2
Phone: (360) 619-6011
Fax: (360) 619-6940

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by telefax or sent by First Class mail or acknowledged delivery.

If to the Transmission Customer:

Coral Power, L.L.C.
4445 Eastgate Mall, Suite 100
San Diego, CA 92121
Attention: Wayne Young
Title: Trader
Phone: Real-Time (858) 320-1500
Fax: (858) 320-1550

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491
Attention: Real-Time Scheduling
Phone: **EMERGENCY ONLY**
(360) 695-2650
Fax: (360) 418-8740

3. **SCHEDULING AGENT**
None.

4. **SIGNATURES**
The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

CORAL POWER, L.L.C.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ BETH BOWMAN**	By: **/S/ ALLAN F. PASCHKE**
Name: **Beth Bowman** *(Print/Type)*	Name: Allan F. Paschke *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **October 11, 2004**	Date: **10/4/04**

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Exhibit A adds transmission service under Table 3.

TABLE 3
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1349232

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2010.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
Coral Power, LLC	Big Eddy Substation 500 kV	BPA	50,000	Nevada-Oregon Border (NOB) 1000 kV	LADWP	50,000	Various [1]
Total Maximum Reserved Capacity			**50,000**			**50,000**	

3. POINT OF RECEIPT

Big Eddy Substation

Location: the point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

[1] Various Receiving Parties – Special Intertie Service.

4. **POINT OF DELIVERY**

Nevada – Oregon Border (NOB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where Bonneville shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
None.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

7. **SERVICE AGREEMENT CHARGES**
Service under this Agreement will be subject to some combination of the charges detailed in this Table 3 and in exhibits B and C. The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff, as amended, and the applicable TBL Transmission and Ancillary Service Rate Schedules, as amended.

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
System Impact and/or Facilities Study Charges are not required at this time for service under this Service Agreement.

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT

None.

9. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

CORAL POWER, L.L.C.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ BETH BOWMAN**	By: **/S/ ALLAN F PASCHKE**
Name: **Beth Bowman** *(Print/Type)*	Name: Allan F. Paschke *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **October 11, 2004**	Date: **10/4/04**

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Exhibit A adds transmission service under Table 4.

TABLE 4
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1349240

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2010.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
Coral Power, LLC	Big Eddy Substation 500 kV	BPA	50,000	Nevada-Oregon Border (NOB) 1000 kV	LADWP	50,000	Various [1]
Total Maximum Reserved Capacity			**50,000**			**50,000**	

3. POINT OF RECEIPT

Big Eddy Substation

Location: the point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

[1] Various Receiving Parties - Special Intertie Service.

4. POINT OF DELIVERY

Nevada – Oregon Border (NOB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where Bonneville shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

5. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION

None.

6. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

7. SERVICE AGREEMENT CHARGES

Service under this Agreement will be subject to some combination of the charges detailed in this Table 4 and in exhibits B and C. The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff, as amended, and the applicable TBL Transmission and Ancillary Service Rate Schedules, as amended.

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
System Impact and/or Facilities Study Charges are not required at this time for service under this Service Agreement.

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT
None.

9. SIGNATURES
The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

CORAL POWER, L.L.C.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ BETH BOWMAN**	By: **/S/ ALLAN F PASCHKE**
Name: **Beth Bowman** *(Print/Type)*	Name: Allan F. Paschke *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **October 11, 2004**	Date: **10/4/04**

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Dated 3/12/97
Service Agreement No. 97TX-10031

AUTHENTICATED

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
MORGAN STANLEY CAPITAL GROUP INC.

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Exhibit A (Point-to-Point Service Transmission (Tariff))
Exhibit B (Application for Point-to-Point Transmission Service)
Exhibit C (Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit D (System Impact Study Agreement)
Exhibit E (Facility Study Agreement)
Exhibit F (Transmission Scheduling Provisions)
Exhibit G (Confirmation Request for Short-Term PTP)
Exhibit H (Wholesale Power and Transmission Rate Schedules)
Exhibit I (Facilities Charges)
Exhibit J (Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 21st day of March 1997, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and Morgan Stanley Capital Group Inc.(hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

W I T N E S S E T H :

WHEREAS BPA provides Transmission Service under BPA's Point-to-Point (PTP) Tariff; and

WHEREAS the Transmission Customer desires to receive Transmission Service under the PTP Tariff;

NOW, THEREFORE, in consideration of the promises and mutual covenants and agreements herein contained, the Parties do agree as follows:

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 Terms and Conditions. The terms and conditions under which the PTP Transmission Service is offered and accepted are pursuant to this Service Agreement and to the PTP Transmission Service Tariff. The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference and made a part of this Service Agreement as Exhibit "A." Unless otherwise mutually agreed in writing by the Parties, BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Federal Energy Regulatory Commission (FERC) that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 Application. The Application for PTP Transmission Service requested by the Transmission Customer and accepted by BPA for this Service Agreement is hereby

incorporated by this reference and made a part of this Service Agreement as Exhibit "B."

1.3 **Statement of Specifications for Long-Term Firm Transmission Service.** The Statement of Specifications (including Ancillary Services) for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer and accepted by BPA are hereby incorporated by reference and made a part of this Service Agreement as Exhibit "C."

1.4 **System Impact/Facilities Study.** Study Agreements for a System Impact Study and/or a Facilities Study, if performed for this Application, are hereby incorporated by this reference and made a part of this Service Agreement as Exhibits "D" and "E," respectively.

1.5 **Transmission Scheduling Provisions.** The Transmission Scheduling Provisions are hereby incorporated by reference and made a part of this Service Agreement as Exhibit "F." All transactions which must be scheduled under this Service Agreement shall be scheduled in accordance with the scheduling provisions in Section 2.7(d) of the Tariff and Exhibit F of this Service Agreement.

1.6 **Reservation Confirmation for Short-Term PTP.** The Confirmation Request for Short-Term PTP is hereby incorporated by reference and made part of this Service Agreement as Exhibit "G." The service specifications for Short-Term Firm and Nonfirm transmission service under this Service Agreement shall be as provided in Exhibit G.

1.7 **BPA Wholesale Power and Transmission Rates Schedules.** The BPA Wholesale Power and Transmission Rates Schedules are hereby incorporated by reference and made part of this Service Agreement as Exhibit "H."

1.8 **Facilities Charges.** All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated by reference and made a part of this Service Agreement as Exhibit "I."

1.9 **Ancillary Services.** The Ancillary Services for PTP Transmission Service under this Service Agreement requested by the Transmission Customer and accepted by BPA are hereby incorporated by this reference and made a part of this Service Agreement as Exhibit "J." Each of the Ancillary Services applicable to all executed short-term reservation confirmation requests shall be specified in Exhibit G.

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence on 2400 hours on March 31, 1997, and shall terminate on 2400 hours on September 30, 2001, unless terminated earlier pursuant to Section 9.9 of the Tariff. All obligations and liabilities incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 **Charges for Transmission Service.** The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the rate schedules as specified below.

4.1.1 All applicable charges pursuant to the PTP Transmission Rate as specified in Exhibit H (PTP-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.2 All applicable charges pursuant to the Ancillary Products and Services Rate for such services as specified in Exhibit G and Exhibit J (APS-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.3 Reserved Nonfirm Transmission Rate as specified in Exhibit G ((RNF-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.4 Energy Transmission Rate as specified in Exhibit H (ET-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.5 Advance Funding Rate for facilities listed in Exhibit I (AF-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.6 Use-of-Facilities Rate for facilities listed in Exhibit I (UFT-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.7 Southern Intertie Rate as specified in Exhibit C and Exhibit G (IS-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules).

4.1.8 Montana Intertie Rate as specified in Exhibit C and Exhibit G (IM-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.2 **Billing and Payment.** Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and all such bills shall be due and payable in accordance with Section 20 of the Tariff.

4.3 **Commitment to Five-Year Rate.** The Transmission Customer agrees that prior to October 1, 2001, it hereby waives its rights to: (a) decrease such amount (in megawatts (MW)) of Long-Term Firm Transmission Demand, as set forth in Exhibit C; and (b) terminate service pursuant to Section 9.9 of the Tariff. BPA

agrees that such amounts constitute a firm commitment of transmission demand through September 30, 2001. BPA will charge the Transmission Customer for such initial MW of Long-Term Firm Transmission Demand amount at the rates established for such service pursuant to the PTP-96, IS-96, or IM-96 rate schedules, and the Transmission Customer agrees to pay such rates, pursuant to and consistent with, the Transmission Settlement Agreement, as adopted in Administrator's Record of Decision adopting the 1996 Final Rate Proposal (Document No. WP-96-A-02, part 2 of 2, Attachment 1), dated April 4, 1996. The Transmission Customer's right to dispute any rate increase proposed by BPA prior to October 1, 2001, shall be pursuant to the Transmission Settlement Agreement as cited above.

4.4 **Load Reduction Due to Changes in Federal or State Law.** The Transmission Customer shall provide written notice to BPA as soon as practicable in the event that a retail consumer of the Transmission Customer obtains access to a power supplier other than the Transmission Customer because a regulatory, legislative, or judicial body of competent jurisdiction, not including any governing body, commission, or board of the Transmission Customer, has required that the Transmission Customer provide such access through the use of the Transmission Customer's transmission and/or distribution facilities, and the Transmission Customer thereby suffers a reduction in retail load. At a mutually agreeable time thereafter, BPA and the Transmission Customer shall initiate discussions to determine whether a change in the Transmission Customer's Network Load pursuant to Exhibit C, Network Load, is appropriate and, if so, the mitigation, if any, to which BPA is entitled.

4.5 BPA Appropriations Refinancing Act, Public Law 104-134

Consistent with Section 3201(i) of Public Law No. 104-134:

4.5.1 BPA shall establish rates and charges on the basis that:

4.5.1.1 the principal amount of an old capital investment shall be no greater than the new principal amount established under Section 3201(b) of Public Law 104-134;

4.5.1.2 the interest rate applicable to the unpaid balance of the new principal amount of an old capital investment shall be no greater than the interest rate established under Section 3201(c) of Public Law 104-134;

4.5.1.3 any payment of principal of an old capital investment shall reduce the outstanding principal balance of the old capital investment in the amount of the payment at the time the payment is tendered; and

4.5.1.4 any payment of interest on the unpaid balance of the new principal amount of an old capital investment shall be a credit against the appropriate interest account in the amount of the payment at the time the payment is tendered.

4.5.2 apart from charges necessary to repay the new principal amount of an old capital investment as established under Section 3201(b) of Public Law 104-134 and to pay the interest on the principal amount under Section 3201(c) of Public Law 104-134, no amount may be charged for return to the U.S. Treasury as repayment for or return on an old capital investment, whether by way of rate, rent, lease payment, assessment, user charge, or any other fee;

4.5.3 amounts provided under Section 1304 of Title 31, U.S. Code, shall be available to pay, and shall be the sole source for payment of, a judgment against or settlement by BPA or the United States on a claim for a breach of this section; and

4.5.4 the contract provisions specified in this section do not:

4.5.4.1 preclude BPA from recovering, through rates or other means, any tax that is generally imposed on electric utilities in the United States, or

4.5.4.2 affect BPA's authority under applicable law, including Section 7(g) of the Pacific Northwest Electric Power Planning and Conservation Act, to:

4.5.4.2.1 allocate costs and benefits, including but not limited to fish and wildlife costs, to rates or resources, or

4.5.4.2.2 design rates.

4.5.5 Terms used in this section shall have the same meaning as they have under Section 3201(b) of Public Law 104-134.

4.5.6 References in this section to Section 3201 of Public Law 104-134 are to that section as approved by the 104th Congress and signed by the President in April of 1996.

(e) Terms used in this section shall have the same meaning as they have under Section 3201(b) of Public Law 104-134.

(f) References in this section to Section 3201 of Public Law 104-134 are to that Section as approved by the 104th Congress and signed by the President in April of 1996.

ARTICLE 5
NOTICES

5.1 **Notices Relating to Provisions of Service Agreement.** Any notice, request, demand, or statement which may be given to or be made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in paragraph 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If the notice is to the Transmission Customer:

Morgan Stanley Capital Group Inc.
Commodities Department, Fourth Floor
1585 Broadway
New York, NY 10036
Attn: Mr. Simon Greensheilds, Vice President

If the notice is to BPA:

Senior Account Executive for Morgan Stanley Capital Group Inc.
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

5.2 **Notices of An Operating Nature.** Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified transmission service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should the same not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The point of contact pursuant to this section shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
SYSTEM OPERATIONS

The Transmission Customer having Point(s) of Interconnection and Points of Delivery with the Federal Columbia River Transmission System (FCRTS) shall be required to designate a Control Area and to comply with the System Operation and Interconnection Requirements in Section 7.4 of the Tariff prior to commencement of Transmission Service hereunder. Point of Interconnection and Points of Delivery not on the Transmission Customer's system shall be governed by agreements between BPA and those interconnected parties.

ARTICLE 7
SPECIFICATIONS FOR ANCILLARY SERVICES

Ancillary Services provided by BPA under this Service Agreement shall be provided in accordance with Section 8 of the Tariff and billed in accordance with Section 20 of the Tariff. The Ancillary Services provided to the Transmission Customer shall be specified in

all executed reservation confirmations in Exhibit G and in the Ancillary Services Exhibit J of this Service Agreement.

ARTICLE 8
MISCELLANEOUS

8.1 **Interconnection With Other Systems.** Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

8.2 **Governing Law.** This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

8.3 **Amendments.** Except as provided in Article 1.1 and Article 8.4, and unless otherwise mutually agreed in writing by the Parties, BPA may change this Service Agreement upon, and only upon, a determination by the Commission that such change is just, reasonable and not unduly discriminatory or preferential. Otherwise, this Service Agreement may be amended only upon mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

8.4 **Revision of Exhibits.** If any changes to Exhibits C, D, E, F, G, H, I, or J are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such nonrate changes.

8.4.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties mutually agree to change Exhibit C pursuant to this Service Agreement, BPA shall prepare and issue a revised Exhibit C. BPA reserves the unilateral right to amend contiguous Point of Delivery provisions in Exhibit C, footnote no. 2, of this Service Agreement.

8.4.2 If the Parties mutually agree to perform study agreements for a System Impact Study and/or Facilities Study under this Service Agreement, BPA shall prepare a revised Exhibit D and/or Exhibit E incorporating such studies.

8.4.3 For changes to any of the provisions contained in the Transmission Scheduling Provisions Exhibit (Exhibit F) to reflect current practice, BPA shall prepare a new Exhibit F.

8.4.4 For changes to the Reservation Confirmation for Short-Term PTP (Exhibit G) to reflect current practice, BPA shall prepare a new Exhibit G.

8.4.5 Except as provided in paragraph 4.3, BPA may change rates pursuant to applicable law and procedures. BPA shall prepare a new Exhibit H incorporating such changes.

8.4.6 BPA reserves the right to revise Exhibit I annually to reflect changes in: (a) the yearly noncoincidental demands on the facility under this Service Agreement and other agreements; (b) changes in interest and amortization (I&A) annual cost ratio; and (c) changes in operation and maintenance (O&M) annual cost.

8.4.7 If the Parties mutually agree to change Exhibit J, section 1, pursuant to this Service Agreement, BPA shall prepare and issue a revised Exhibit J. BPA reserves the right to update loss methodology consistent with Exhibit J, section 2 to incorporate values which represent current FCRTS operating conditions or to incorporate any value, used in the exhibit to calculate the losses, which has changed due to a change in methodology.

8.5 Conversion to Any Tariffs Offered by BPA. Upon mutual agreement of the Parties, the notice periods for terminating this Service Agreement and for commencing service under another tariff offered by BPA may be shortened.

8.6 Severability. In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by FERC or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

8.7 **Computation of Time.** On computing any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of this period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next business day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

8.8 **No Third Party Beneficiaries.** This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto expressly do not intend to create any obligation or promise of performance to any other third person or entity nor have the Parties conferred any right or remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns to enforce this Service Agreement.

8.9 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

8.10 **Successors and Assigns.** This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

8.11 **Service Agreement Governs.** In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

8.12 **Entire Agreement.** Except as stated otherwise herein, this Service Agreement constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect thereof.

IN WITNESS WHEREOF, the duly authorized representatives of BPA and the Transmission Customer have executed this Service Agreement as of the date first above written.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ TIM CASTILLE
Senior Account Executive

Name Timothy P. Castille
(Print/Type)

Date 3-13-97

MORGAN STANLEY CAPITAL GROUP INC.

By /S/ SIMON GREENSHIELDS

Name **Simon Greenshields**
(Print/Type)

Title **Vice President**

Date **March 20 97**

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

1. TERM OF TRANSACTION

Start Date: , at 2400 hours.
Termination Date: The earlier of: (a) 2400 hours on _____; or (b) 2400 hours on the termination date established pursuant to Article 3 of this Service Agreement.

2. DELIVERING PARTY/RESOURCE

3. RECEIVING PARTY

4. CONTROL AREA

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point of Interconnection (Voltage)	Transmission Demand (MW)	Point of Delivery (Voltage)	Transmission Demand (MW)
Substation kV		Substation kV	
Maximum Transmission Demand	1/		1/ 2/

[Note: Does Maximum Transmission Demand cover losses?]

[Use footnote 1 if a Short-Distance Discount applies]_____

1/ The Short-Distance Discount (SDD) is applied to the Transmission Customer's monthly Transmission Demand for the purpose of computing the monthly bill. Reference Exhibit C, Section 10, for the SDD transmission demand.

[Use footnote 2 if contiguous Points of Delivery applies]_____

2/ The Transmission Customer's designated contiguous Points of Delivery are subject to the following terms.

(a) All Points of Delivery on the delivery side must be interconnected through a transmission or distribution system, and operated normally closed. The Points of Delivery must be significantly interconnected electrically on both high side and low side.

(b) In the event of a credible outage, each Point of Delivery within the contiguous set must be capable of providing electric backup service to any other Point of Delivery of that contiguous set so that retail customers within the load center served by the contiguous set of Points of Delivery realize no interruption in service.

(c) All Points of Delivery in the set of contiguous Points of Delivery must be located on the same side of a constraint or potential constraint. Shifts in loads from one Point of Delivery to another Point of Delivery in the contiguous set may not adversely affect any constraint, such as those posted on BPA's Open Access Same-Time Information System (OASIS).

(d) The Transmission Customer may not direct BPA to deliver a specific amount of demand to a specific Point of Delivery within the contiguous set of Points of Delivery. BPA has no obligation to deliver specific amounts to the delivery points which constitute the contiguous set of Points of Delivery. BPA has no obligation to construct new facilities at or between Points of Delivery included in the contiguous set of Points of Delivery as long as BPA can deliver the combined demand to the contiguous set of Points of Delivery.

(e) All Points of Delivery within the contiguous set of Points of Delivery must be in a single control area; all power associated with the contiguous set of Points of Delivery must be scheduled.

(f) All Points of Delivery associated with the Southern Intertie are specifically excluded from consideration as part of a contiguous set of Points of Delivery. Big Eddy, John Day, California/Oregon Border (COB), and Nevada/Oregon Border (NOB) are independent Points of Delivery.

(g) The utility requesting contiguous Points of Delivery must be capable of receiving electric service at each of the Points of Delivery in the contiguous set. If the utility is requesting contiguous Points of Delivery in order to deliver to a third party, then that third party must be capable of receiving delivery at each of the Points of Delivery in the contiguous set.

(h) Where appropriate, the Transmission Customer must agree to use limits on the individual Points of Delivery included in the contiguous set of Points of Delivery.

(i) Contiguous Points of Delivery are granted for real power only. Issues associated with reactor power shall be covered by separate procedures.

(j) These criteria shall be reviewed annually. An individual customer's situation shall be reviewed if there are any changes in how its system is served or impacted by any transmission system conditions. BPA reserves the right to modify any characteristics of a customer's contiguous Point of Delivery if changes in a system warrant such modification.

(k) The Transmission Customer is entitled to receive 90 days written notice from BPA of changes to the contiguous Point of Delivery provisions listed in this footnote.

6. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) **Substation**

Location:

Voltage: kV

Transmission Demand: MW

Metering:

Delivering Party/Resource:

Control Area:

7. DESCRIPTION OF POINTS OF DELIVERY

(a) **Point of Delivery**

Name of Point of Delivery

Location:

Voltage:

Metering:

Loss Adjustment. If applicable, BPA will adjust for transmission losses between the Transmission Customer's point of delivery and point of metering. Such adjustments shall be specified in written correspondence between BPA and the Transmission Customer.

Exceptions. [If none, delete the following sub-items]

(1) **Period of Service**
(Applicable when the Point of Delivery is not yet in service or is scheduled to be removed.)

(2) **Future Voltage**
(Applicable when the voltage is scheduled to be changed.)

(3) **Demand Limits**

(4) **Phase**
(Applicable when BPA is delivering single phase, not 3-phase power.)

(5) **Service Over Other Facilities**
(Applicable when BPA uses the Transmission Customer's own facilities or a third party's facilities to serve the Transmission Customer's.)

(6) **Default Methodology for Calculating Hourly Amounts of Transmission Customer's Generation**
(Applicable when the existing meters only measure monthly amounts.)
In some cases, the resource will be treated as an offset to the Transmission Customer's load. Consumer resources are not subject to this requirement.

(7) **Calculation Methods For Determining How Meter Readings Are To Be Added or Subtracted to Calculate the Billing Amounts**

(8) **Multiplier To Be Used To Calculate Demand From Average Energy Deliveries in Points of Delivery Without Demand Recording Devices**

(b) **Point(s) of Delivery Served by Transfer [Include only if it applies]**
The Transmission Customer, its Agent, or its power supplier is responsible for arrangements required to transmit power over the facilities of the Intervening System described in this section to Points of Delivery contained herein. To the extent the Transmission Customer is reliant upon agreements between BPA and the Intervening System owner for such arrangements, or if BPA has otherwise arranged to provide financial assistance to the Transmission Customer to secure such transmission service to the Points of Delivery from the Intervening System owner, service to the Transfer Points of Delivery are subject to the PTP-96 rate schedule, or its successor.

Transmission Service under this Service Agreement shall encompass all Integrated Network Transmission System facilities, as defined by the Tariff, necessary to serve the Transmission Customer's Network Load.

Name of Transfer Point [*list Point of Replacement here]*

Location

Voltage

BPA's Point of Receipt from Intervening System *[include only if applicable]*

Transmission Customer Point of Receipt and Point of Metering. [*list the locations where the Transmission Customer takes final receipt of power from the transferor. If the Point of Metering is different than the Point of Receipt, list Point of Metering under a separate heading]*

Loss Adjustment. If applicable, BPA will adjust for transmission losses between the Transmission Customer's point of receipt and point of metering. Such adjustments shall be specified in written correspondence between BPA and the Transmission Customer.

Exception

8. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

9. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE [Only include if using transfer, if yes, include name of transfer agent]**

10. **SHORT DISTANCE DISCOUNT**
[0.6 + (0.4 x transmission distance/75)]

Points of Delivery	Circuit Miles from (Name POI)	Adjusted SDD POI Demand (kW) */	Adjusted SDD POD Demand (kW) */
Substation			
Substation			

*/ The SDD is not available for transmission service to secondary points of interconnection or delivery.

SYSTEM IMPACT STUDY AGREEMENT

A System Impact Study is not required at this time for the service under this Service Agreement.

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FACILITY STUDY AGREEMENT

A Facility Study is not required at this time for the service under this Service Agreement.

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TRANSMISSION SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

The purpose of this exhibit is to describe how the Parties will effect transmission transactions under this Service Agreement.

2. EXHIBIT PROVISIONS

(a) **Scheduling Principles**

The procedures in this exhibit are intended to achieve the following principles:

(1) promote efficient system operations; and

(2) provide workable scheduling procedures for the timely delivery of power.

(b) **Control Area Requirements**

(1) In order to schedule power, a Transmission Customer must designate a Host Control Area (HCA) as defined by North American Electric Reliability Council (NERC) to implement its schedules. The HCA may be the sending Control Area, the receiving Control Area, or an intermediary Control Area.

(2) BPA shall be the HCA for any transaction involving either:

(A) generation located within BPA's Control Area; or

(B) service to a load within BPA's Control Area.

(3) If BPA is the intermediary Control Area in a single transaction or set of transactions, the Transmission Customer may designate a HCA other than BPA. The Transmission Customer must inform BPA of its choice no later than the time of preschedule. BPA has no obligation to accept schedules from any HCA that does not agree to abide by the scheduling requirements set forth in this exhibit.

(4) If the Transmission Customer has designated a HCA for a single schedule, it must remain the HCA for the entire duration of the schedule. In the event the Transmission Customer fails to identify a HCA for its next schedule, BPA will assume that the designated HCA is the same entity as designated for the Transmission Customer's last schedule. Any designation changes shall be made pursuant to Article 5.1 of this Service Agreement.

(5) The Transmission Customer may arrange interchange schedules; however, the HCA shall confirm and then implement the interchange schedule. The HCA is responsible to the Western Systems Coordinating Council and NERC for the interchange scheduling arrangements of the Transmission Customer, including the responsibility for resolving any inadvertent energy accumulation that may result from the Transmission Customer's incorrect or uncoordinated scheduling of the interchange.

(6) Any Transmission Customer for whom BPA is the HCA must schedule transmission to or from BPA's Control Area, i.e., the Transmission Customer's Scheduling Agent is BPA for purposes of scheduling transmission under this exhibit.

(7) Any Transmission Customer or its Scheduling Agent using a HCA other than BPA must establish and verify schedules with other Control Areas through the HCA, but the HCA is responsible for implementing and assuring the accuracy of the schedule.

(c) **Coordinating Requirements**

(1) All schedules must be provided to BPA on Workdays (defined as any day *both* Parties consider a workday).

(2) Schedules apply to the following day or days (if the following day or days are not Workdays).

(3) Scheduled hourly values are to be referenced by the "hour ending" time on the 24-hour clock (i.e., the schedule for 2-3 p.m. is referred as the "hour ending 15").

(4) Unless otherwise agreed, all schedules will be effectuated on an hourly basis using the standard 20-minute ramp period centered on the hour (i.e., beginning 10 minutes prior to the hour and ending 10 minutes after the hour).

(5) All schedules with BPA are to be stated in Pacific Time (PT) and are to begin with the hour ending 1.

(6) The Transmission Customer or its Scheduling Agent agrees to submit all hourly prescheduled quantities in whole megawatthour amounts.

(d) **Prescheduling Requirements**
Prescheduling is the process of establishing hourly schedules through the following Workday(s).

(1) **Preschedule Submissions**

(A) The Transmission Customer or its Scheduling Agent agrees to submit schedule(s) covering all transactions into, out of, or within BPA's Control Area.

(B) BPA may require Transmission Customers or its Scheduling Agent to submit *estimated* preschedules prior to the final preschedule.

(C) The Transmission Customer or its Scheduling Agent agrees to submit a *final* hour*ly* preschedule for the next day or days by 1000 of each Workday.

(E) The maximum number of preschedule days is 4 days, except that by mutual agreement BPA may accept preschedules for up to 5 or 6 days as needed to accommodate a Transmission Customer's special scheduling requirements for contiguous weekend-holiday periods. (For example, BPA will accept schedules for the period Thanksgiving Thursday through Monday if the Transmission Customer observes the Friday after Thanksgiving as a holiday.)

(2) **Information Required to Be Included in Preschedule**
Any schedule submitted to BPA by the Transmission Customer or its Scheduling Agent must include, at a minimum, the following information:

(A) the HCA;

(B) the supplier, receiver, and wheeling entities involved in the transaction;

(C) the MW amount of the schedule;

(D) the starting and ending times for each schedule;

(E) the transmission service being scheduled; and

(F) the point of receipt/delivery for the transaction.

(e) **Changes from Preschedule**

(1) The Transmission Customer or its Scheduling Agent may not change the hourly amounts of its preschedules except by mutual agreement with BPA. The Transmission Customer's generation that provides automatic generation control is exempt from this requirement.

(2) To the extent changes from the preschedule become necessary, the Transmission Customer or its Scheduling Agent must submit such requests no later than 30 minutes prior to the scheduled hour for which the change becomes effective.

(3) Multihour changes from preschedule shall specify an "hour beginning" and an "hour ending" and shall never be stated as "until further notice."

(4) Upon a Transmission Customer's or its Scheduling Agent's request, BPA will consider mid-hour changes from preschedule under critical operating conditions such as loss of a resource or transmission path. The Transmission Customer or its Scheduling Agent and BPA must agree to the effective time, ramp duration, integrated, and revised net

schedules for mid-hour changes. Mid-hour schedule changes shall not be made for economic or load shaping purposes. Such changes are subject to applicable charges.

(f) **Wheeling Requirements**

(1) **Scheduling Requirements for Wheeled Power**
The Transmission Customer's Scheduling Agent and HCA must ensure that any wheeling contract(s) to which they are a party on behalf of the Transmission Customer provide(s) for the following:

(A) The Transmission Customer or its Scheduling Agent must arrange schedules with affected wheeling entities to or from the agreed-upon point of receipt/delivery.

(B) If BPA provides wheeling service, including those for which BPA is the HCA, the Transmission Customer or its Scheduling Agent must notify BPA of changes to wheeling arrangements no later than 30 minutes prior to the scheduled hour for which the wheeled energy transaction becomes effective.

(C) The Transmission Customer or its Scheduling Agent must acquire Transmission consistent with BPA's Transmission Reservation and Scheduling Procedures and the PTP and NT Tariffs.

(g) **Emergency Requirements**

(1) **Loss of Transmission Path**

(A) The path operator shall notify affected Transmission Customers, their Scheduling Agent and HCA as rapidly as possible of the loss of a transmission path.

(B) The path operator will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify schedules, as required, per the established effective time, and agree on integrated and revised net schedules.

(2) **Loss of Generating Resource**
The Transmission Customer agrees to adhere to the following requirements for any resources that it operates and agrees to ensure, through contractual arrangement, that any entity operating a resource on its behalf likewise agrees to the following:

(A) The operating entity (generating entity) will notify BPA and affected Transmission Customers, their Scheduling Agent, and HCA as quickly as possible of the resource loss.

(B) The entity with Control Area responsibility will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify schedules, as required, as of the established effective time, and agree on integrated and revised net schedules.

(3) **General Provisions Regarding Emergencies**
BPA and the Transmission Customer, its Scheduling Agent, and HCA agree to expedite communications to avoid accumulation of inadvertent powerflows or net schedules which place a control burden on other Control Areas.

(h) **After-the-Fact Reconciliation**
The Transmission Customer or its Scheduling Agent agrees to reconcile all schedules and accounts each week with a final reconciliation at the end of each month consistent with the following principles:

(1) The Transmission Customer or its Scheduling Agent and BPA will verify all scheduled transmission.

(2) The Transmission Customer or its Scheduling Agent and BPA will agree on current product balances, loss calculations, and loss schedules, where appropriate.

(3) The Transmission Customer or its Scheduling Agent will assist BPA, as necessary, to reconcile all inadvertent energy in a timely manner.

3. EXHIBIT REVISIONS
The provisions in this Exhibit may be revised by agreement of the Parties.

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Department of Energy

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666

Date: 03/28/97
To: Phone:
Attn: Fax:

RESERVATION CONFIRMATION
Short-Term Point-to-Point

The following memorializes the terms of a transmission transaction agreed to by Bonneville Power Administration Transmission Business Line ("BPA/TBL") and on _____. Transactions hereunder are in accordance with the reference contract listed below.

Reference Contract	97TX- 96XXX	
BPA Confirmation #97TX-	967XX	**Customer Reference No:**
Reservation Desk Contact		()
Customer Contact		**Customer Presched Desk:**
Transmission Seller	BPA Transmission Business Line	()
Transmission Buyer		()
Confirmation Start Date		**Customer Real Time Desk:**
Confirmation End Date		()
Delivery Days of the Week		()
Delivery Hours		
		BPA SW TBL Preschedule No:
Transmission Demand (MW)		**(360) 418-2501**
		BPA NW TBL Preschedule No:
Type of Service (D,W,M)		**(360) 418-2217**
Firm or Nonfirm	Firm or Nonfirm	
Transmission Rate(s)		**BPA Real-time Desk No: Power and Transmission**
Loss Factors		**(360) 418-2189 or 2188**
Loss Return Method		
		Transmission Reservation Desk:
Transmission Price		**(360) 418-8499**
Curtailment Rights		**Fax No. Transmission Scheduling:**
		(360) 418-8208
Point of Interconnection		
POI Control Area		
Delivering Party		
Point of Delivery		
POD Control Area		
Receiving Party		
Scheduling Agent		
Modify LTF/STF?	Yes (See Page 2) or No	

Scheduling: All transmission service transactions will be shown in Pacific Time. Transmission Customer shall preschedule all transactions by 10 a.m., or as mutually agreed, on the day that both Parties observe as a workday preceding the date of transaction. Schedules may only be changed due to uncontrollable forces on either system or by mutual agreement of both Parties. Scheduling and Dispatch are provided by BPA.

Billing: Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and all such bills shall be due and payable in accordance with Section 20 of the Tariff.

Ancillary Services: Applicable Ancillary Services shall be provided by the same provider as listed in Exhibit J if the Transmission Customer also has Long-Term Transmission under this Service Agreement.

Energy Imbalance	[provider]
Control Area Reserves for Resources	[provider]
Control Area Reserves for Interruptible Purchases	[provider]
Load Regulation	[provider]

Other: **List curtailment rights or description of LTF/STF modifications, with secondary POI/PODs and the associated demands.**

This confirmation agreement contains all of the terms and conditions of this transaction and may not be varied or contradicted by any other writing without the express agreement of the BPA Transmission Business Line and the Transmission Customer.

Please copy this fax, sign it, and return it via fax to BPA by 4 p.m. Pacific Time, (Date Reservation Confirmation is sent to Transmission Customer). Additionally, please mail a copy with your original signature to Transmission Supply, noting the routing: TMS.

AGREED AND ACCEPTED

Bonneville Power Administration TBL	**Transmission Customer**
/s/ _____	/s/ _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

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FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

1. USE-OF-FACILITIES COSTS FOR WHICH TRANSMISSION CUSTOMER IS RESPONSIBLE

(a) Calculation of Charges Pursuant to the UFT-96 Rate Schedule.

Facility	Investment 1/	I&A Annual Cost Ratio 2/	I&A Annual Cost	O&M Annual Cost 3/	Sum of Non-Coincidental Demands	$/kW/yr
Substation	$	%	$	$		$
			Total UFT Charge =		$0./kW/mo.	
			kW to apply UFT charge to:		0 kW	

1/ 199X computation.
2/ Based on ACR table dated _____
3/ Based on O&M table dated _____

(b) New Investments In Facilities Serving The Transmission Customer. If new investments are proposed by BPA and agreed to by the Transmission Customer in accordance with the provisions of Sections 11 and 12 of the Tariff, such investments shall be used in the use-of-facilities (UFT) charge under this Service Agreement. Investments of routine or emergency equipment replacements which do not need Transmission Customer approval, shall also be included in the UFT charge under this Service Agreement.

(c) Changes in Costs and Demands. This Exhibit I may be revised annually to reflect changes in: (a) the yearly noncoincidental demands on the facility under this Service Agreement and other agreements; (b) changes in I&A annual cost ratio; and (c) changes in O&M annual cost.

2. DIRECT ASSIGNMENT FACILITIES CHARGES

[List any facilities designated as Direct Assignment Facilities and the Rate]

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ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA(TBL)	
(b)	**Energy Imbalance**	[provider]	
(c)	**Control Area Reserves for Resources**	[provider]	
(d)	**Control Area Reserves for Interruptible Purchases**	[provider]	
(e)	**Load Regulation**	[provider]	

(f) **Transmission Losses.**

[Specify here how the Transmission Customer will handle losses, (i.e., purchase from BPA, return the losses, purchase losses from a third party).]

Compensation for losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) Federal Power Losses: Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96 and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

Transmission loss obligations associated with the delivery of other classes of Federal power shall be established pursuant to the Transmission Customer's contract for the purchase of such power.

(2) FCRTS Losses per the election made pursuant to Section 1(f)(4) below: The Transmission Customer shall provide compensation to BPA for losses incurred when providing transmission service over the FCRTS for amounts of power integrated at Points of Integration, except those amounts associated with purchases specified in 1(f)(1) above, by

multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in Section 2 and

(a) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(b) purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses; or

(c) returning the resulting amount of energy to BPA from either the Transmission Customer's system or from the system of a third party 168 hours after the time of delivery of power for which loss compensation is required, excepting, however, that losses resulting from use of Delivery Facilities, calculated pursuant to 1(f)(3), below, shall be returned on a mutually agreeable basis, but no later than 720 hours after delivery of power for which loss compensation is required.

(3) Delivery Facilities - Delivery Facility losses shall be determined, for each billing cycle, pursuant to the following procedure: (a) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; (b) multiplying the resulting ratio by the total amount delivered to the Transmission Customer less amounts described in 1(f)(1) above; and (c) multiplying the result derived in step 1(f)(3)(b) by the Delivery Facility loss factor listed below in Section 2. Delivery Facility losses are not scheduled for return.

(4) The Transmission Customer shall notify BPA of its method of compensation for losses for all network resources, in writing, 30 days prior to the first day of delivery schedules and 30 days prior to the first day of October each subsequent year during the term of this Service Agreement. In the event the Transmission Customer does not identify their Transmission Losses Compensation Method, in writing, 30 days prior to the first day of delivery schedules and 30 days prior to the first day of October each subsequent year, the default for the Transmission Customer is to purchase losses using the flat rate under

the APS-96 Rate Schedule or its successor. (Period ending September 30, may be less than one year based on start date of Service Agreement.)

Transmission Customer's Method of Compensation of Losses for year one:
The Transmission Customer shall purchase Transmission Losses for the period covering April 1, 1997 - September 30, 1997 at the following rate:

Jan. '97 - March '97	April '97 - June '97	July '97 - Sept. '97
18.55 mills/kWh	11.48 mills/kWh	18.01 mills/kWh

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kilowatthour (kWh) delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA may review and not more frequently than once in a 12-month period may revise this Exhibit as appropriate to incorporate values which represent then current FCRTS operating conditions or to incorporate any value, used in such Exhibit to calculate the losses, which has changed due to a change in methodology. any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with the Transmission Customer. BPA shall prepare a new Exhibit J incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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AUTHENTICATED

Amendment No. 1
Contract No. 97TX-10031

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

MORGAN STANLEY CAPITAL GROUP INC.

This AMENDMENT to the Transmission Service Agreement, Contract Number 97TX-10031 (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and Morgan Stanley Capital Group Inc. (herein after referred to as "the Transmission Customer") The Transmission Customer and BPA are sometimes referred to individually as "Party", and collectively as "Parties" as the context suggests below.

This Amendment No. 1 (Amendment) to the Agreement between BPA and the Transmission Customer acknowledges the Parties' desire to extend the term of the Agreement to 2400 hours September 30, 2015. The Parties agree that all other terms and conditions of the Agreement remain the same. Article 3 of the Agreement is hereby amended to read as follows:

> "Service under this Service Agreement shall commence at 2400 hours on March 31, 1997. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on September 30, 2015; or (b) 2400 hours on the date of termination established by the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied."

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

MORGAN STANLEY CAPITAL GROUP INC.

By /S/ SIMON GREENSHIELDS

Name Simon Greenshields
(Print/Type)

Title Vice President

Date Jan - 27 - 2001

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ KIPPEN R. MOXNESS
Transmission Account Executive

Name Kippen R. Moxness
(Print/Type)

Date 12-21-2000

(TM-TMC-W:\TMC\CT\Morgan Stanley\10031AA1)

AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission demand of 50 MW from the Big Eddy Substation Point of Interconnection (POI) and to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 16
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 582503

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: at 0000 hours on December 31, 2005.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1,000 kV)	BPA	See Sect. 3 Below		Transmission Customer

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (POI) (Voltage)	Point(s) of Delivery (POD) (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1,000 kV)	01/01/05 - 12/31/05 50 MW	IS-02

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

4. **DESCRIPTION OF POINT(S) OF INTERCONNECTION**

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities to be scheduled.

5. **DESCRIPTION OF POINT(S) OF DELIVERY**

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ PATRICK MURRAY**	By: **/S/ ALAN PASCHKE for**
Name: **Patrick Murray** *(Print/Type)*	Name: Richard A. Gillman *(Print/Type)*
Title: **Vice President**	Title: Transmission Account Executive
Date: **9/4/03**	Date: **8/29/03**

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission service in the amount of 50 MW from the Big Eddy Substation Point of Interconnection (POI) to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 17
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 907059

1. TERM OF TRANSACTION

Start Date: 0000 hours on January 1, 2004.
Termination Date: 0000 hours on January 1, 2006.

The Transmission Customer understands that because of the work Los Angeles Department of Water and Power has currently scheduled on the Celilo (DC Southern Intertie) Modernization Project, the Transmission Provider may not have transmission capacity to provide service under this Table for all or part of the months of October, November and December, 2004 or for all or parts of certain months during 2005 if the work is rescheduled or delayed. The Transmission Customer shall nevertheless pay the full long-term firm PTP transmission service charge based upon a demand of 50 MW plus ancillary service and any other appropriate charges. Also the Transmission Customer shall pay for this transmission service each month during the term of this Table including the months of October, November and December, 2004 and the months during 2005 for which transmission capacity may be unavailable due to the Celilo Modernization Project.

This paragraph is not intended to affect the Transmission Provider's right to curtail service pursuant to the Tariff during any other months or the Transmission Customer's obligation to pay the full transmission service charge and other charges in the event the Transmission Provider curtails transmission service pursuant to the Tariff at any time during 2004 for reasons other than the Celilo Modernization Project.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1,000 kV)	BPA	See Sect. 3 Below		Transmission Customer

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

POI (Voltage)	POD (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1,000 kV)	01/01/04 - 01/01/06 50 MW	IS-04

4. DESCRIPTION OF POINT(S) OF INTERCONNECTION

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities to be scheduled.

5. DESCRIPTION OF POINT(S) OF DELIVERY

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.

By: /S/ PATRICK MURRAY

Name: Patrick Murray
(Print/Type)

Title: Vice President

Date: 11/18/03

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ CLIFFORD C PERIGO

Name: Clifford C. Perigo
(Print/Type)

Title: Senior Transmission Account Executive

Date: 11-12-03

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission demand of 50 MW from the Big Eddy Substation Point of Interconnection (POI) and to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 18
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 1348790

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2008.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	50,000	NOB (1,000 kV)	BPA	50,000		Transmission Customer

3. DESCRIPTION OF POINT(S) OF INTERCONNECTION

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

4. **DESCRIPTION OF POINT(S) OF DELIVERY**

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

5. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

6. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ SIMON GREENSHIELDS**	By: **/S/ YOUNG S. LINN**
Name: **Simon Greenshields** *(Print/Type)*	Name: Young S. Linn *(Print/Type)*
Title: **VP**	Title: Transmission Account Executive
Date: **9/21/04**	Date: **9/17/04**

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission demand of 50 MW from the Big Eddy Substation Point of Interconnection (POI) and to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 19
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 1348797

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2008.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	50,000	NOB (1,000 kV)	BPA	50,000		Transmission Customer

3. DESCRIPTION OF POINT(S) OF INTERCONNECTION

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

4. **DESCRIPTION OF POINT(S) OF DELIVERY**

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

5. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

6. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ SIMON GREENSHIELDS**	By: **/S/ YOUNG S. LINN**
Name: **Simon Greenshields** *(Print/Type)*	Name: Young S. Linn *(Print/Type)*
Title: **VP**	Title: Transmission Account Executive
Date: **9/21/04**	Date: **9/17/04**

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(AUTHENTICATED COPY)

Contract No. DE-MS79-87BP92412

SALE AND EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF GLENDALE

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Exhibit A (Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions)..... 8

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This SALE AND EXCHANGE AGREEMENT, executed as of January 28, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF GLENDALE, CALIFORNIA (Glendale), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Glendale is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Glendale, the City of Burbank (Burbank), the City of Pasadena (Pasadena), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which

provides, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Glendale, Burbank, and Pasadena; and

WHEREAS this Agreement and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Glendale desires to purchase and Bonneville desires to sell surplus firm capacity with energy under the terms specified herein; and

WHEREAS Bonneville and Glendale also desire to enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Term.

This Agreement, when executed, shall become effective at 2400 hours January 31, 1988, and shall terminate at 2400 hours on April 15,

2008; provided, however, that no power sales may occur subsequent to January 31, 2008. All obligations incurred hereunder shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

2(a) "Agreement" means this sale and exchange agreement between Bonneville and Glendale.

2(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

2(c) "Contract Demand" means the maximum hourly rate of delivery for surplus firm power when this Agreement operates as a sale, or for capacity when this Agreement operates as an Exchange. This amount is 5 MW for Block 1 and 5 MW for Block 2, and may be modified by Glendale pursuant to section 4. However, Contract Demand, when used in subsection 7(d), shall mean 10 MW, as may be modified by Glendale pursuant to section 4.

2(d) "Contract Year" means the year beginning at 2400 hours on June 30 and ending at 2400 hours the following June 30.

2(e) "Embedded Transmission Costs" means a charge equal to the Nonfirm Rate portion of Bonneville's IS-87 Southern Intertie Transmission Rate Schedule or successor rate to the extent Glendale uses the Pacific Northwest-Pacific Southwest DC Intertie to provide Supplemental Energy to Bonneville; provided, however, that if the Nonfirm Rate portion of IS-87 or successor rate is terminated prior to the expiration of this Agreement, the Parties agree to use an equivalent substitute value calculated using the same methodology Bonneville used to derive the Nonfirm Rate portion of IS-87. Embedded Transmission Costs also shall include a charge equal to Bonneville's ET-87 Energy Transmission Rate Schedule or successor rate to the extent Glendale provides Supplemental Energy either generated from its resources located outside of Los Angeles County or delivered to Glendale's points of delivery located outside of Los Angeles County.

2(f) "Energy Account" means an account consisting of (i) monthly totals of the amount of Peaking Replacement Energy and Exchange Energy obligated to be delivered to Bonneville during each month, the delivery of which energy Bonneville has declined pursuant to the provisions of paragraph 7(e)(1), and (ii) the value of such declined energy for each month converted to mills/kWh pursuant to paragraph 7(e)(4). For each month there will be two values in the Energy Account: a total amount of energy declined and the value of such energy in mills/kWh.

2(g) "Exchange" means the capacity for energy exchange terms and conditions as described in this Agreement.

2(h) "Exchange Energy" for Block 1 as defined in subsection 5(a) means the energy Glendale is obligated to deliver to Bonneville in equal weekly increments throughout the year in Exchange for Bonneville deliveries of capacity on an annual basis. Exchange Energy for Block 2 as defined in subsection 5(b) means the energy Glendale is obligated to deliver to Bonneville during the period November 16 through April 15 in exchange for Bonneville making available capacity during the preceding May 15 through October 14 period.

2(i) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie transmission lines cross the Nevada-Oregon border.

2(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission capacity due to physical limitations, or (ii) the physical transmission capacity of the DC Intertie is reduced to zero for a period of time which is less than 24-consecutive hours.

2(k) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Glendale during periods when this Agreement operates as an Exchange or capacity sale pursuant to Section 12.

2(l) "Peaking Replacement Energy" means an amount of energy which Glendale is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

2(m) "PNW Coordination Agreement" means the contract among Bonneville and Pacific Northwest (PNW) generating entities, providing for coordinated operation of resources, designated as Contract No. 14-03-48221, as amended or replaced.

2(n) "Supplemental Energy" means the energy Glendale is obligated to make available as a purchase option for Bonneville, pursuant to section 7.

2(o) "Total Incremental Cost" means incremental fuel cost, incremental operation and maintenance, generating unit start-up cost, transmission losses incurred by Glendale in delivering Supplemental Energy to the Point of Delivery, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Glendale in supplying Supplemental Energy to Bonneville that would not otherwise have been incurred.

2(p) "Total Outage" means the physical transmission capacity of the DC Intertie is reduced to zero, whether planned or unplanned, for a period of time which equals or exceeds 24-consecutive hours.

2(q) "UIC" means any unrecoverable incremental costs beyond normal operations incurred by Glendale in generating or acquiring

Supplemental Energy for which Bonneville rescinds its request pursuant to paragraph 7(c)(3). UIC includes, but is not limited to, direct costs, penalties, cancellation fees for fuel commitments, transmission services, or unrecoverable energy purchases, but excludes general engineering, scheduling, and administrative charges. UIC shall not include costs incurred by Glendale to the extent that Glendale is able to make use of such Supplemental Energy and in doing so mitigates costs it has incurred or avoids costs it would otherwise have incurred.

2(r) "Workday" means each day which both Bonneville and Glendale observe as a regular workday.

3. Exhibits.

Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), General Contract Provisions (Form PSC (SW-1)) (Exhibit B), Plan of Delivery (Exhibit C), Minimum Monthly Energy Distribution Tables for Glendale (Exhibit D), and Operating Procedures (Exhibit E) are attached hereto and hereby made a part of this Agreement.

4. Option for Glendale to Increase Purchase.

Not later than June 1, 1988, Glendale, Burbank, and Pasadena may, upon written notice, increase their power purchase by a total of 60 MW, or more, if Bonneville determines power is available for this purpose.

To the extent that any such increase results in an increase for Glendale pursuant to this Agreement, then that increase shall become effective for the Contract Year beginning at 2400 hours on June 30, 1988, and shall be distributed equally to Blocks 1 and 2 for both the surplus firm power sale and Exchange under this Agreement. This Agreement shall be amended as necessary to reflect such increase.

5. Surplus Firm Power Sale.

5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Glendale shall purchase 9,966 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Glendale shall purchase during each Contract Year 24,090 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Glendale shall purchase during each Contract Year while this Agreement remains a power sale, 26,280 MWh of surplus firm energy.

5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available

and Glendale shall purchase 9,180 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing until 2400 hours on June 30, 1992, Glendale shall purchase 2,820 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, and continuing until 2400 hours on October 14, 1992, Glendale shall purchase 6,996 MWh of surplus firm energy. Beginning at 2400 hours on May 14, 1993, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Glendale shall purchase 10,098 MWh of surplus firm energy.

5(c) Adjustments to Amount of Power.

The above MWh quantities for Glendale shall be adjusted as necessary to account for any increase pursuant to section 4. However, in the event of a partial Contract Year power sale for Block 1, or in the event of a partial May 15 through October 14 power sale for Block 2, Glendale shall purchase the appropriate monthly amounts of surplus firm energy under Block 1 and under Block 2 as shown in the applicable plan of delivery for such Contract Year pursuant to subsection 5(e). Glendale may increase the energy scheduled for purchase from Bonneville for any month under the then-current plan of delivery, if such energy is available as determined by Bonneville for such purpose. Such increases shall not affect the plan of delivery, the minimum monthly energy delivery in any future months during such Contract

Year, nor shall any such increase affect the take-or-pay energy amount in any future Contract Year.

5(d) Rates of Delivery.

The maximum hourly rates of delivery for surplus firm power shall be 5 MW from October 15 through May 14 and 10 MW from May 15 through October 14, as may be modified by Glendale's option to increase pursuant to section 4.

5(e) Distribution of Monthly Amounts.

Prior to January 1 of each year, Glendale shall submit a plan of delivery to Bonneville showing the distribution of the monthly amounts of energy for the following 4 Contract Years in the form represented by Exhibit C. Glendale shall distribute the monthly amounts of energy within the limits indicated in Exhibit D.

5(e)(1) If requested by Glendale, Bonneville shall consult with Glendale at the time such plans of delivery are being prepared. Bonneville will share its most recent information on its ability to serve Glendale with a power sale for the following 4 Contract Years and any other considerations that may relate to the plans of delivery. Bonneville shall include such plans of delivery in its PNW Coordination Agreement planning.

5(e)(2) The Parties shall rely upon the most recent plan of delivery submitted to Bonneville for the amount of energy to be delivered in the upcoming July. Bonneville shall notify Glendale at the earliest opportunity, but not later than August 15, if other than that most recent proposed plan of delivery shall become effective for the balance of the Contract Year. Unless otherwise agreed by the Parties, notwithstanding the limits indicated in Exhibit D, the total of the monthly amounts Bonneville shall deliver during July and August shall equal the 2-month July and August total energy amount specified in the plan of delivery ultimately adopted for use during that Contract Year; provided, however, that in the event that Glendale is unable to receive the minimum amount of energy during August due to the timing of such notice, then the Parties shall adjust deliveries as necessary prior to November 16 to provide for any energy not received during August.

5(e)(3) If Bonneville adopts a plan of delivery other than the most recent plan of delivery submitted, Bonneville shall adjust the adopted plan of delivery to reflect the most recent Intermountain Power Project scheduled maintenance outages.

5(f) Distribution of Weekly Amounts.

Within any month, Glendale shall not take more than 135 percent of that month's average weekly amount in any Calendar Week. Such average weekly amount shall be equal to the total MWh for that month as specified in the applicable plan of delivery, divided by the number of days in that month, and multiplied by 7.

5(g) Operational Flexibility.

Glendale may request changes of up to 5 percent of any monthly amount of energy to be made available under the Agreement, with no less than 2 months' advance written notice. Such changes shall not be unreasonably denied by Bonneville, and the ability to make such changes shall be at no additional cost to Glendale. The effect of such changed monthly amount on subsequent monthly amounts of energy shall be included in this notice; provided, however, that changes in monthly amounts purchased hereunder shall not be reduced below the minimum monthly amounts of energy specified in Exhibit D, unless mutually agreed to by the Parties.

6. Conversion to the Exchange.

The sale of surplus firm power shall convert to the Exchange if Bonneville has a surplus firm energy insufficiency under the conditions described in this section; provided, however, that Glendale shall have the option to either: (i) remain in the power sale mode

until after other similar long term sale and exchange agreements executed with parties outside of the Pacific Northwest region for which initial deliveries shall commence after January 1, 1988, have been converted to an exchange; or (ii) convert to the Exchange prior to the conversion of such other similar long term sale and exchange agreements. Glendale shall exercise its option within 14 days after Glendale receives Bonneville's written notice that it will be converting this Agreement or such other similar agreements to an exchange.

6(a) Preliminary Notice.

6(a)(1) If Bonneville determines in the PNW Coordination Agreement planning process that there is a possibility of insufficient surplus firm energy to satisfy the surplus firm energy obligation to Glendale in the next Contract Year, Bonneville shall provide written notice to Glendale as soon as possible. Following this notice, the Parties may, upon mutual agreement, begin the Exchange at 2400 hours on May 14 or on a subsequent date prior to 2400 hours on June 30 of the then-current Contract Year.

6(a)(2) If Bonneville determines in the planning process that there is a certainty of insufficient surplus firm energy for the next Contract Year, Bonneville shall provide written notice to Glendale as soon as possible, but not later than June 15. In this event, regardless of the

extent to which PNW system refill occurs, the Exchange shall begin at 2400 hours on June 30. Glendale's Exchange Energy obligation for Block 2 shall be adjusted to account for a start date of July 1 rather than May 15.

6(b) Final Notice.

If the Exchange does not begin pursuant to subsection 6(a), then the provisions of this subsection apply. The completion of PNW Coordination Agreement planning and the adoption by Bonneville of a particular plan of delivery for Glendale shall occur after July 31. Bonneville shall provide written notice to Glendale as soon as possible after July 31, but not later than August 15, whether service at the Contract Demand shall continue as a power sale or convert to the Exchange. If such notice specifies a conversion to the Exchange, then the Exchange shall begin no sooner than 14 days after the date of receipt of such notice by Glendale. Conversion to the Exchange shall be effective for the remainder of the Contract Year from the time specified in Bonneville's notice to Glendale, or as provided for in subsection 6(c). Glendale's Exchange Energy obligation shall be adjusted to account for the start date specified in the notice rather than May 15.

6(c) Reversion to Power Sale.

After conversion to the Exchange, whenever Bonneville determines that it has sufficient surplus firm energy to deliver the amounts

of surplus firm power specified in subsections 5(a) and 5(b) for the ensuing Contract Year, deliveries under this Agreement shall revert to the surplus firm power sale pursuant to section 5, unless Glendale has provided written notice to Bonneville which describes a contract offer to acquire a resource to replace the energy no longer available from Bonneville due to the conversion to the Exchange. Such notice shall include the amount of energy to be acquired and the term of the proposed acquisition. Bonneville shall respond as follows:

Bonneville shall, within 21 days of receipt of such notice, notify Glendale as to whether this transaction shall revert to the power sale for the duration of Glendale's proposed energy acquisition. If this transaction is to revert to the power sale, Bonneville shall notify Glendale of the basis for the reversion, and such power sale shall begin by the later of (1) 31 days from receipt by Bonneville of Glendale's notice, or (2) the effective date of energy deliveries pursuant to Glendale's proposed acquisition, and shall continue for the duration of Glendale's acquisition, subject to the provisions of section 12. If Bonneville elects not to have the transaction revert to the power sale, then Bonneville shall waive its right to revert to the power sale for the duration of Glendale's contractual commitment for the proposed energy acquisition. Prior to the termination of Glendale's acquisition contract, Bonneville shall, upon written notice of at least 30 days, have the right to revert to the power sale as described in section 5 at the termination of Glendale's acquisition.

6(d) The notice provisions of subsections 6(a) and 6(b) shall apply to reversion from Exchange to power sale, as well as the conversion from power sale to Exchange, except as may be modified by the provisions of subsection 6(c).

7. Capacity For Energy Exchange.

Upon conversion to the Exchange, Bonneville shall make 5 MW of capacity available to Glendale for Block 1 on an annual basis and 5 MW of capacity for Block 2 from May 15 through October 14 each year, as may be modified by Glendale's option to increase pursuant to section 4. Glendale shall be obligated to deliver Peaking Replacement Energy to Bonneville during these periods of capacity deliveries as specified in subsection 7(a). In Exchange for Bonneville deliveries of capacity, Glendale shall deliver Exchange Energy and make available Supplemental Energy to Bonneville, as specified in subsections 7(b) and 7(c).

7(a) Deliveries of Capacity and Peaking Replacement Energy.

At times when the Exchange is in effect, Bonneville shall make available to Glendale capacity in an amount up to the Contract Demand each hour, up to 10 hours times the Contract Demand each day Monday through Saturday, including holidays, not to exceed 50 hours times the Contract Demand each week. Glendale shall be obligated to deliver to Bonneville Peaking Replacement Energy for the amounts of Peaking Energy delivered to Glendale by 2400 hours

on the day following the Peaking Energy delivery, except as provided in subsection 7(e). Return of Peaking Replacement Energy during any hour shall not exceed 100 percent of the Contract Demand in any hour, unless otherwise mutually agreed by the parties.

7(b) Exchange Energy.

Glendale shall be obligated to deliver Exchange Energy to Bonneville as provided herein. The amount of such energy provided each Contract Year shall equal the exchange ratio in kWh/kW for each block of capacity, multiplied by the Contract Demand in kilowatts for each block of capacity. For Block 1, the exchange ratio is 2,536 kWh/kW; for Block 2, the exchange ratio is 975 kWh/kW. Exchange Energy for Block 1 shall be delivered in equal weekly increments throughout the year and Exchange Energy for Block 2 shall be delivered in equal weekly increments from November 16 through April 15, except as provided in subsection 7(e). Such equal weekly increments shall be adjusted as necessary to account for an uneven number of weeks during any Exchange Energy delivery period. In the event of a partial Contract Year of capacity deliveries, the amount of Exchange Energy which Glendale is obligated to deliver to Bonneville shall be reduced on a pro rata basis to account for such partial Contract Year.

7(c) Supplemental Energy.

7(c)(1) Glendale shall be obligated to make Supplemental Energy available to Bonneville during each November 16 through April 15 while this Agreement operates as an Exchange. The total amount of such energy provided each Contract Year shall equal the supplemental ratio in kWh/kW multiplied by the Block 2 Contract Demand in kilowatts of capacity. The supplemental ratio is 1,200 kWh/kW. Bonneville may elect to purchase up to the maximum amount of Supplemental Energy available to Bonneville in any Contract Year by serving a notice to Glendale not less than 2 months prior to the desired delivery date, or on shorter notice if agreed to by Glendale. Bonneville may issue additional notices during any Contract Year for amounts of Supplemental Energy not previously requested in a notice. Any such notice shall specify the amount of Supplemental Energy desired by Bonneville and provide a nonbinding proposed schedule for deliveries of Supplemental Energy. Glendale shall promptly notify Bonneville if such proposed schedule is unacceptable to Glendale and the reasons therefor. Glendale shall not unreasonably deny Bonneville's proposed schedule. In the event that the Parties are unable to agree on a proposed schedule, then the requested Supplemental Energy shall be delivered in equal hourly increments during the delivery period specified in Bonneville's notice and during the

hours specified in paragraph 7(d)(3). Bonneville and Glendale shall finalize the schedule for deliveries of weekly blocks of Supplemental Energy within 15 Workdays of receipt by Glendale of Bonneville's notice. Deliveries of Supplemental Energy are subject to Glendale's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Glendale's generation or transmission capability. In the event of any such constraints, Glendale shall reschedule such deliveries in a timely manner. In the event of an extended generation constraint, Bonneville may request an alternate available source for Supplemental Energy at another agreed upon price, until such time as the generation constraint is removed.

7(c)(2) Within 15 Workdays of receipt of Bonneville's notice requesting to make available Supplemental Energy, and prior to committing to obtain Supplemental Energy, Glendale shall inform Bonneville of probable resources available, including the estimated price of the lowest cost sources of Supplemental Energy available for purchase, the estimated Total Incremental Cost from such sources, and the UIC for such resources. Glendale shall revise such estimated price, Total Incremental Cost, and UIC if conditions change substantially during the remaining days of the notice period described in

paragraph 7(c)(1). If Glendale determines that the UIC from such sources will exceed 4.5 mills, as escalated pursuant to subsection 9(c), it shall notify Bonneville, and Bonneville shall have the option of either: (1) raising such maximum rate for UIC; (2) relieving Glendale of its obligation to provide Supplemental Energy; or (3) obligating itself to purchase Supplemental Energy. Bonneville shall make this choice in a timely manner. Glendale shall use best efforts to mitigate UIC, but unless earlier notification by Glendale and Bonneville's selection of its option to raise the maximum rate for UIC has occurred, Bonneville's obligation for the amount of energy specified in its notice of rescission shall not exceed 4.5 mills/kWh as escalated pursuant to subsection 9(c).

7(c)(3) Bonneville shall pay Glendale any applicable Embedded Transmission Costs plus 115 percent of Glendale's Total Incremental Cost for providing Supplemental Energy. Bonneville may rescind a notice requesting Supplemental Energy not later than 0930 hours of the Workday immediately preceding the day when such Supplemental Energy was to begin to be provided to Bonneville, and pay Glendale any UIC incurred by Glendale in response to Bonneville's previous request for such energy. Any decision to rescind a notice requesting Supplemental Energy shall apply to the total amount of MWh of

Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1); provided, however, that Bonneville can rescind a portion of the Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1) if Bonneville agrees to pay any new UIC resulting therefrom.

7(c)(4) Bonneville shall submit schedules for the delivery of Supplemental Energy pursuant to the provisions of paragraph 7(c)(1) and section 10. Glendale shall not unreasonably withhold its agreement with such schedules, and Glendale shall deliver weekly amounts of Supplemental Energy by the end of each Calendar Week during the period of deliveries pursuant to the mutually agreed upon schedules for the delivery of Supplemental Energy.

7(d) Delivery Limitations.

7(d)(1) May 15 through October 14.

Unless limited by Bonneville, Glendale shall complete each Calendar Week's deliveries of Exchange Energy by the end of such Calendar Week. The maximum rate of delivery for Peaking Replacement Energy plus Exchange Energy shall be 100 percent of the Contract Demand. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account. Bonneville may limit the delivery rate for

Peaking Replacement Energy plus Exchange Energy to not less than 60 percent of Contract Demand for the Exchange during the period May 15 through October 14. To the extent that Bonneville restricts the delivery on any hour, the restricted quantity of Peaking Replacement Energy and Exchange Energy may either be delivered by Glendale on hours other than the hours specified in paragraph 7(d)(3), or be delivered on the next available normal delivery hour when Bonneville can accept such energy. The Parties may agree to delay the delivery beyond the Calendar Week of delivery, or the Parties may agree to place such energy into the Energy Account, as described in paragraph 7(e)(1).

7(d)(2) November 16 through April 15.

Hourly rates of delivery shall be as mutually agreed upon by Bonneville and Glendale. However, during the period November 16 through April 15, during any hour the total rate of delivery for Exchange Energy plus Supplemental Energy plus Peaking Replacement Energy shall not exceed 250 percent of the Contract Demand, unless mutually agreed to by Bonneville and Glendale. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account.

7(d)(3) Normal Delivery Hours for Peaking Replacement and Exchange Energy.

Although deliveries of Peaking Replacement Energy and Exchange Energy may occur during other hours, the normal delivery hours are as follows:

2200 hours on Monday to 0800 hours on Tuesday
2200 hours on Tuesday to 0800 hours on Wednesday
2200 hours on Wednesday to 0800 hours on Thursday
2200 hours on Thursday to 0800 hours on Friday
2200 hours on Friday to 0800 hours on Saturday
2200 hours on Saturday to 0800 hours on Monday.

7(e) Conditions for Energy Account and Cash-Out of Peaking Replacement and Exchange Energy.

7(e)(1) Declinations of Peaking Replacement Energy and Exchange Energy.

Bonneville may decline deliveries of either Peaking Replacement Energy or Exchange Energy in whole or in part. Bonneville shall provide Glendale with notice by 1400 hours on the Thursday prior to each Calendar Week. Such notice shall specify whether Bonneville will require the delivery of such energy in whole or in part for the next Calendar Week and shall specify the amount of energy which Bonneville declines. To the extent that Bonneville declines the deliveries, the monthly total of such declined energy and its value converted to mills/kWh

pursuant to paragraph 7(e)(4) shall be entered into the Energy Account.

7(e)(2) Withdrawals from the Energy Account.

Bonneville may request to withdraw energy from the Energy Account during a Calendar Week and shall provide Glendale with notice by 1400 hours on the Thursday prior to such Calendar Week. Such notice shall specify the quantity of energy to be withdrawn and the rate of delivery for such energy. However, in addition to other deliveries by Glendale pursuant to this Agreement, the maximum rate of withdrawal from the Energy Account shall not exceed the Contract Demand on any hour, unless mutually agreed. Glendale shall provide such requested energy to Bonneville during the next Calendar Week, subject to Glendale's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Glendale's generation or transmission capability. The value for energy withdrawn from the Energy Account shall be converted to kWh as determined pursuant to paragraph 7(e)(4) and shall be withdrawn on a first-in-first-out basis. To the extent that the value for withdrawn energy is greater than the value for declined energy determined pursuant to paragraph 7(e)(1), Bonneville shall pay Glendale an amount equal to the

difference between the values for withdrawn and declined energy multiplied by the kWh withdrawn. To the extent that the value for withdrawn energy is less than the value for declined energy determined pursuant to paragraph 7(e)(1), Glendale shall pay Bonneville an amount equal to the difference between the values for declined and withdrawn energy multiplied by the kWh withdrawn. Each party shall pay the other pursuant to the provisions of section 8. If mutually agreed, withdrawn energy may be provided on hours other than those specified in paragraph 7(d)(3).

7(e)(3) Cash-Out of Energy in the Energy Account.

Bonneville shall maintain the Energy Account. The Energy Account shall contain monthly totals of (i) the declined energy remaining at the end of each calendar month, and (ii) the value of such energy converted to mills/kWh pursuant to paragraph 7(e)(4). Any monthly total of energy which remains in the Energy Account longer than 11 months shall be cashed out pursuant to subsection 9(b) at the cash-out price at the time the energy was entered into the Energy Account. No more than one monthly total of energy shall be cashed out on any monthly bill rendered to Glendale. Glendale shall pay Bonneville pursuant to the cash-out terms specified in subsection 9(b), and shall be relieved of any obligation

thereafter to provide such monthly total of energy to Bonneville.

7(e)(4) Determination of Value for Energy Entered into Energy Account and Withdrawn from Energy Account.

Following receipt of its gas bill each month, Glendale shall provide Bonneville with a copy of a portion of such bill which shows the dollars per dekatherm paid by Glendale for the total of all gas purchases for that month. Bonneville shall convert this amount to dollars per Btu and apply this ratio to an agreed-upon heat rate of 10,000 Btu per kWh to determine the value in mills per kWh for entries into and withdrawals from the Energy Account during the following month. To the extent that gas is not available or is no longer a significant fuel source for generation by Glendale, the Parties shall negotiate: (i) an alternate significant fuel source which is used by Glendale for generation; and (ii) a methodology to derive a value in mills/kWh for entries into and withdrawals from the Energy Account. This Agreement shall be amended to implement the results of such negotiation.

7(f) At Glendale's request, the Parties agree to negotiate in good faith mutually agreeable terms and conditions which would allow Glendale to deliver energy to Bonneville's system for later use by Glendale.

8. Payment.

8(a) Payment by Glendale.

Bonneville shall render preliminary and final adjusted monthly bills to Glendale. Glendale shall pay Bonneville by the close of business on the twentieth (20th) day after the date of each such preliminary bill and any adjustments that may occur on the final monthly bill. The date of such bills shall be no earlier than the mailing date of such bills. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Glendale, then the due date shall be the next following business day. Other provisions related to payment of bills shall be in accordance with the General Rate Schedule Provisions attached to this Agreement.

8(b) Payment by Bonneville.

Glendale shall render monthly bills to Bonneville. Bonneville shall pay Glendale by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to payment of bills shall be in accordance with the General Rate Schedule provisions attached to this Agreement.

9. Rates and Cash-Out.

9(a) Surplus Firm Power.

9(a)(1) Initial Demand and Energy Rates.

The initial demand and energy rates for deliveries of power under Block 1 and Block 2 are as follows: $4.60/kilowatt-month (kW-mo.) and 20.5 mills/kWh (includes Intertie adder). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery.

9(a)(2) Rate Adjustment During First 5 Years.

The initial demand and energy rates for the period January 1, 1988, through December 31, 1988, are described in paragraph 9(a)(1). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. The energy rates specified in this paragraph 9(a)(2) include the Intertie adder. The rates for calendar years 1989 through 1992 are as follows:

Calendar Year	Capacity ($/kW-mo.)	Energy (mills/kWh)
1989	4.88	21.73
1990	5.17	23.03
1991	5.48	24.42
1992	5.81	25.88

Subsequent to December 31, 1992, the demand and energy rates shall be adjusted pursuant to paragraph 9(a)(3).

9(a)(3) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

Adjustments under this paragraph begin January 1, 1993. For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. On the effective date of any Bonneville Priority Firm Power (PF) rate adjustment thereafter, the rate for surplus firm power (SL_{new}) shall be adjusted as follows:

$$SL_{new} = SL_n * \frac{PF_{new}}{PF_{prev}}$$

where

SL_{new} = The effective surplus firm power demand and energy charges hereunder as adjusted to reflect the change between PF_{new} and PF_{prev}.

SL_n = For the initial adjustment under this paragraph 9(a)(3) the SL_n demand charge shall be $5.81/kW-mo. and the energy charge shall be 25.88 mills/kWh. For all subsequent adjustments under this paragraph, the values for SL_n shall be the then-current values for the previous SL_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be

determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh, in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(b) Cash-out.

Bonneville shall cash out energy pursuant to paragraph 7(e)(3). Glendale shall pay Bonneville for such energy as provided below.

9(b)(1) Initial Cash-out.

The initial level for cash-out shall be 14.9 mills/kWh.

9(b)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any PF rate adjustment after the effective date of this Agreement, the level of the cash-out rate (CO_{new}) shall be adjusted as follows:

$$CO_{new} = CO_n * \frac{PF_{new}}{PF_{prev}}$$

where CO_{new} = The effective level for cash-out as adjusted to reflect a new PF rate.

CO_n = For the initial adjustment under this paragraph 9(b)(2), CO_n shall be 14.9 mills/kWh. For all subsequent adjustments under this paragraph, the values for CO_n shall be the then-current values for the previous CO_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(c) Maximum Rate for UIC Incurred by Glendale if Bonneville Rescinds a Notice for Supplemental Energy.

9(c)(1) Initial Maximum Rate for UIC.

In accordance with subsection 7(c), the initial rate for UIC is 4.5 mills/kWh for the amount of energy specified in Bonneville's notice of rescission.

9(c)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any Priority Firm Power (PF) rate adjustment after the effective date of this

Agreement, the maximum rate for UIC (UIC_{new}) shall be adjusted as follows:

$$UIC_{new} = UIC_n * \frac{PF_{new}}{PF_{prev}}$$

where

UIC_{new} = The effective rate for UIC as adjusted to reflect a new PF rate.

UIC_n = For the initial adjustment under this paragraph 9(c)(2), UIC_n shall be equal to 4.5 mills/kWh. For all subsequent adjustments under this paragraph, the values for UIC_n shall be the then-current values for the previous UIC_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

10. Scheduling Provisions for Power Sale and Exchange.

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

10(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

10(b) Prescheduled amounts shall be submitted by 0930 hours.

10(c) This subsection 10(c) shall apply only to the power sale portion of this transaction. If Glendale desires to schedule other than that month's average weekly amount of energy for such month in any Calendar Week, Glendale shall notify Bonneville by 1400 hours on the Monday preceding such Calendar Week. Glendale may revise such new weekly amount if Glendale notifies Bonneville by 1400 hours on the Thursday preceding such Calendar Week.

10(d) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts that Glendale anticipates it will schedule from Bonneville each day for the following 10 days. Glendale shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Glendale or Bonneville to schedule such amounts.

10(e) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such changes

shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

11. Transmission Limitation.

In the event of an interruption of deliveries by either Party due to a DC Intertie outage, the following provisions shall apply.

11(a) Relief Remedies During Periods of Total Outage.

The Parties shall be relieved of obligations as follows.

11(a)(1) Conditions for Capacity Payment Relief.

The following conditions must be met each Contract Year for relief to be given as described in paragraph 11(a)(2): (i) the duration of a single Total Outage exceeds 360-consecutive hours, in which case relief is provided for the remainder of such Total Outage only; or (ii) the sum of all Total Outages for the Contract Year exceeds 720 hours, excluding Total Outages, if any, for which relief was given pursuant to item (i) above.

11(a)(2) Determination of Capacity Payment Relief.

For the duration of the Total Outages which occur subsequent to the occurrence of relief as described in

paragraph 11(a)(1), Glendale shall receive a capacity credit in the form of a reduction in the demand rate per kW-mo. calculated by determining such duration of the Total Outage during the billing month, divided by the total number of hours in that month.

11(a)(3) Energy Payment Relief During Power Sale.

Without regard to the duration of a Total Outage, if Glendale is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Glendale shall be relieved of its obligation to pay for such amounts of energy. To the extent that Glendale is unable to receive energy during any month, the monthly minimum take-or-pay energy specified in the applicable plan of delivery shall be reduced by an amount of energy determined as follows: a ratio shall be calculated, the numerator being the number of hours of Total Outage during the month that Glendale is unable to receive energy, and the denominator being the total number of hours in that month. This ratio is then multiplied by the monthly energy specified in the applicable plan of delivery to determine such amount of energy. This amount of energy shall be subtracted from such monthly energy to determine the revised monthly amount for that month. The total take-or-pay energy for Block 1, or Block 2 if

applicable, as specified in Exhibit D, shall be reduced by the amount of energy as calculated above.

11(a)(4) Energy Payment Relief During Exchange.

11(a)(4)(A) For Total Outages which occur subsequent to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Glendale's obligation to deliver Peaking Replacement Energy owed to Bonneville for previous capacity delivered by Bonneville, and Supplemental Energy requested by Bonneville pursuant to subsection 7(c) remain. Glendale's obligation to deliver Exchange Energy associated with a Total Outage up to one year remains, but, at Bonneville's option, either: (i) Glendale shall deliver such energy to Bonneville subject to mutually agreed upon schedules following the end of the Total Outage and Bonneville shall pay Glendale's Total Incremental Cost for the first 3 months of such obligation and 115 percent of Glendale's Total Incremental Cost for the following 9 months; or (ii) Glendale shall be relieved of its obligation to deliver such energy.

11(a)(4)(B) For Total Outages which occur prior to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Glendale shall reschedule deliveries of Peaking Replacement Energy, Exchange Energy, and Supplemental Energy which Glendale is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the Total Outage, or at other times as mutually agreed by the Parties.

11(b) Relief Remedies During Periods of Partial Outage.

11(b)(1) Relief Remedies During the Power Sale.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue deliveries under this Agreement. The Parties also shall curtail pro rata on an hourly basis all agreements executed on or before January 1, 1988, for firm energy or capacity based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over agreements executed after January 1, 1988 for firm energy or capacity. If Glendale is unable to receive any amounts of energy, Bonneville shall be relieved of

its obligation to deliver and Glendale shall be relieved of its obligation to pay for such amounts of energy.

11(b)(2) Relief Remedies During the Exchange.

During the Exchange, or during any period of the power sale when Bonneville has restricted surplus firm energy deliveries pursuant to section 12 and is delivering capacity only, the following provisions shall apply.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue or reschedule deliveries under this Agreement. The Parties shall curtail all agreements for firm capacity without energy or deliveries of exchange energy executed prior to January 1, 1988, pro rata on an hourly basis, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over deliveries of capacity or exchange energy pursuant to agreements executed after January 1, 1988. Glendale shall reschedule interrupted or curtailed deliveries of Peaking Replacement Energy, Exchange Energy and Supplemental Energy which Glendale is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the

interruption or curtailment, or at other times and under conditions as mutually agreed by the Parties.

12. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of 16 U.S.C. § 837 (1984) (P.L. 88-552), and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to those provisions, Bonneville shall have the right to restrict all or a portion of the capacity or energy if such capacity or energy is needed to meet the capacity or energy requirements, as the case may be, in the PNW. Such restrictions shall be limited in amounts and duration to cover the projected need specified in the written notice which Bonneville shall provide to Glendale. The sale of surplus firm power shall resume pursuant to the applicable plan of delivery for the remainder of the then-current Contract Year after expiration of the period of restriction except as described in the immediately following sentence. If a projected period of restriction exceeds 2 months' duration, Glendale may make other arrangements for energy for the remainder of such Contract Year if Glendale has entered into a contractual commitment with a third party as a direct result of Bonneville's prior notice of restriction, and Bonneville has received Glendale's written notice of such arrangements not later than 10 days prior to the projected end of such period of restriction.

uch written otice shall pecify the date n which a eriod of estriction begins nd the date on hich such period f restriction is rojected to end.

During any period that Bonneville continues to have surplus firm energy on a planning basis, but Bonneville restricts the delivery of

energy as provided above, Bonneville shall make available capacity at the Contract Demand and, in the event of a partial energy restriction, a pro rata amount of energy. Prior to the effective date of the restriction, Glendale shall give notice to Bonneville of the amount of capacity made available by Bonneville that Glendale desires for the anticipated duration of the restriction. In such notice, Glendale may reduce the amount of capacity it desires for the anticipated period of restriction below the Contract Demand, with no change in the rate per kW-mo. of capacity specified in section 9; provided, however, that if Glendale reduces the amount of capacity it desires during a period of restriction to zero, and the reduction to zero capacity occurs on any day other than the last day of a month, then Bonneville shall make a pro rata reduction in the rate per kW-mo. of capacity. Terms for the delivery of such capacity and for the cash-out or delivery of Peaking Replacement Energy shall be as provided in this Agreement.

13. Points of Delivery.

13(a) Points of Delivery.

The point of delivery for all deliveries pursuant to this Agreement is NOB.

13(b) Other Pacific Southwest Points of Delivery.

Notwithstanding the point of delivery specified in subsection 13(a), at Bonneville's request, Glendale shall

deliver energy owed Bonneville to Pacific Southwest points of delivery where Glendale has interconnections and available transmission capacity with Pacific Southwest utilities.

13(c) Costs Incurred to Point of Delivery.

Each Party shall bear its own costs for deliveries to the point of delivery under subsections 13(a) and 13(b); provided, however, that all deliveries of Supplemental Energy by Glendale to Bonneville pursuant to subsection 7(c) shall be excluded from the provisions of this subsection.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ James J. Jura
Administrator

Date January 28, 1988

CITY OF GLENDALE, CALIFORNIA

By /s/ David Ramsay

Title Asst. City Manager

Date 11/25/87

14. Limit of Liability.

It is mutually understood and agreed that Glendale's obligations for the payment of monies pursuant to this Agreement are limited to revenues received by Glendale from the sale of electric power and/or the disposition of assets of Glendale's power generation and transmission facilities.

PLAN OF DELIVERY

1. Monthly Amounts of Energy Requested by Glendale Pursuant to Subsection 5(e).

Year / Month	1988	1989	1990	1991
July				
August				
September				
October				
November				
December				
January				
February				
March				
April				
May				
June				

This attachment will be revised each year upon Glendale's submission of new data.

2. Example, assuming 1992 Power Sale.

Upon Glendale's submittal of plans of delivery each year in accordance with subsection 5(e), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations. Assuming energy sufficient to serve Glendale load as a power sale, the plan of delivery to be used is based upon the degree to which the coordinated system refills.

At 2400 hours on July 31, 1992, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will implement the most recent plan of delivery submitted by Glendale. If the system does not refill, such parties will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier "Critical Periods"). This can be shown as follows:

Critical Period	Glendale's Plan of Delivery
1992 - 1995 (refill)	year 1992 from 1992 submittal
1991 - 1994	year 1992 from 1991 submittal
1990 - 1993	year 1992 from 1990 submittal
1989 - 1992	year 1992 from 1989 submittal

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 5 MW DEMAND			BLOCK 2: 5 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	30%	= 1,116					1,116
F	30%	= 1,008					1,008
M	40%	= 1,488					1,488
A	50%	= 1,800					1,800
M	55%	= 2,046	May (15-31)	50%	= 1,020		3,066
J	55%	= 1,980		50%	= 1,800		3,780
J	65%	= 2,418 1/		50%	= 1,860 1/		4,278
A	65%	= 2,418 1/		55%	= 2,046 1/		4,464 2/
S	65%	= 2,340		50%	= 1,800		4,140
O	50%	= 1,860	Oct. (1-14)	15%	= 252		2,112
N	30%	= 1,080					1,080
D	30%	= 1,116					1,116
TOTAL		20,670			8,778		
TAKE-OR-PAY		24,090 3/			9,180 3/		
BLOCK 1 LF = 55%				BLOCK 2 LF = 50%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).
3/ These figures will be increased on July 1, 1992, pursuant to page 2 of this Exhibit D.

(WP-PKLD-3464c)

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 5 MW DEMAND			BLOCK 2: 5 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	30%	= 1,116					1,116
F	30%	= 1,008					1,008
M	40%	= 1,488					1,488
A	50%	= 1,800					1,800
M	55%	= 2,046	May (15-31)	50%	= 1,020		3,066
J	55%	= 1,980		50%	= 1,800		3,780
J	65%	= 2,418 1/		50%	= 1,860 1/		4,278
A	65%	= 2,418 1/		55%	= 2,046 1/		4,464 2/
S	65%	= 2,340		50%	= 1,800		4,140
O	50%	= 1,860	Oct. (1-14)	15%	= 252		2,112
N	30%	= 1,080					1,080
D	30%	= 1,116					1,116
TOTAL		20,670			8,778		
TAKE-OR-PAY		26,280			10,098		
BLOCK 1 LF = 60%				BLOCK 2 LF = 55%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

(WP-PKLD-3464c)

OPERATING PROCEDURES

No operating procedures have been established as of the date of execution of this Agreement.

Prior to conversion to the Exchange, the Parties agree to develop operating procedures which shall be utilized during the Exchange. Such procedures shall include, but are not limited to, determination and verification of Total Incremental Cost, determination and verification of UIC, operating procedures under the Energy Account, and operating procedures during periods of Total Outage and Partial Outage.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in this Agreement.

Amendatory Agreement No.1
Contract No. DE-MS79-87BP92412

June 14, 1988

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF GLENDALE

This AMENDATORY AGREEMENT, executed as of July 8, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF GLENDALE, CALIFORNIA (Glendale), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Glendale is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS on January 28, 1988, Glendale and Bonneville executed Contract No. DE-MS79-87BP92412 (Sale and Exchange Agreement), which provides, among other things, for Bonneville to sell surplus firm capacity with energy to Glendale; and

WHEREAS the Sale and Exchange Agreement also provides that Bonneville and Glendale shall enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS in accordance with the provisions of section 4 of the Sale and Exchange Agreement, Glendale has exercised its option to increase the power purchase from 5 MW for Block 1 and 5 MW for Block 2 to 10 MW for Block 1 and 10 MW for Block 2; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Effective Date of Amendatory Agreement.

This Amendatory Agreement, when executed, shall become effective at 2400 hours on June 30, 1988.

2. Amendment of Sale and Exchange Agreement.

The Sale and Exchange Agreement, Contract No. DE-MS79-87BP92412, is hereby amended as follows:

(a) Subsection 5(a) is deleted and replaced by the following:

"5(a) Amounts of Power Under the Annual Sale (Block I).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Glendale shall purchase 9,966 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Glendale shall purchase during each Contract Year 48,180 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and

Glendale shall purchase during each Contract Year while this Agreement remains a power sale, 52,560 MWh of surplus firm energy."

(b) Subsection 5(b) is deleted and replaced by the following:

"5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Glendale shall purchase 2,820 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on October 14, 1988, Bonneville shall make available and Glendale shall purchase 12,720 MWh of surplus firm energy.

Beginning at 2400 hours on May 14, 1989, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Glendale shall purchase 18,360 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at

2400 hours on May 14, 1992, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Glendale shall purchase 20,196 MWh of surplus firm energy."

(c) Exhibit D, which was effective at 2400 hours on January 31, 1988, is deleted and replaced by the attached Exhibit D.

3. Signature Clause The signatories hereto represent that they have been appropriately authorized to enter this Amendatory Agreement behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Amendatory Agreement

CITY OF GLENDALE
DATE 7/1/88
APPROVED AS TO FINANCIAL PROVISION FOR $1,400,000 est. pay as you go
Director of Finance

CITY OF GLENDALE, CALIFORNIA
By
Title City Manager
Date 7/8/88

(VS6-PMC-3730c)

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By
Administrator
Date JUN 2 8 1988

APPROVED AS TO FORM
Assistant City Attorney
DATE 6-30-88

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 10 MW DEMAND			BLOCK 2: 10 MW DEMAND			TOTAL MWh
	LF	=	MIN. MWh	LF	=	MIN. MWh	
J	30%	=	2,232				2,232
F	30%	=	2,016				2,016
M	40%	=	2,976				2,976
A	50%	=	3,600				3,600
M	55%	=	4,092	May (15-31) 50%	=	2,040	6,132
J	55%	=	3,960	50%	=	3,600	7,560
J	65%	=	4,836 1/	50%	=	3,720 1/	8,556
A	65%	=	4,836 1/	55%	=	4,092 1/	8,928 2/
S	65%	=	4,680	50%	=	3,600	8,280
O	50%	=	3,720	Oct. (1-14) 15%	=	504	4,224
N	30%	=	2,160				2,160
D	30%	=	2,232				2,232
TOTAL			41,340			17,556	
TAKE-OR-PAY			48,180 3/			18,360 3/	
BLOCK 1 LF = 55%				BLOCK 2 LF = 50%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).
3/ These figures will be increased in 1992, pursuant to page 2 of this Exhibit D.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 1/ 10 MW DEMAND			BLOCK 2: 10 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	30%	= 2,232					2,232
F	30%	= 2,016					2,016
M	40%	= 2,976					2,976
A	50%	= 3,600					3,600
M	55%	= 4,092	May (15-31)	50%	= 2,040		6,132
J	55%	= 3,960		50%	= 3,600		7,560
J	65%	= 4,836 2/		50%	= 3,720 2/		8,556
A	65%	= 4,836 2/		55%	= 4,092 2/		8,928 3/
S	65%	= 4,680		50%	= 3,600		8,280
O	50%	= 3,720	Oct. (1-14)	15%	= 504		4,224
N	30%	= 2,160					2,160
D	30%	= 2,232					2,232
TOTAL		41,340			17,556		
TAKE-OR-PAY		52,560			20,196		
BLOCK 1 LF = 60%				BLOCK 2 LF = 55%			

1/ The total take-or-pay energy amount for Block 1 shall be effective at 2400 hours on June 30, 1992.
2/ July and August in both Blocks have maximum load factors of 75%.
3/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).

EXHIBIT C
CONTRACT NO. DE-MS79-87BP92412
CITY OF GLENDALE

PLAN OF DELIVERY

Monthly Amounts of Surplus Firm Energy (in MWH)

BLOCK # 1

Contract Year:	2000/01	2001/02	2002/03	2003/04
Month				
July	5,580	5,580	5,580	5,580
August	5,580	5,580	5,580	5,580
September	5,360	5,360	5,360	5,360
October	4,100	4,100	4,100	4,100
November	3,225	3,225	3,225	3,225
December	3,310	3,310	3,310	3,310
January	4,420	4,420	4,420	4,420
February	3,925	3,925	3,925	3,925
March	3,575	3,575	3,575	3,575
April	4,060	4,060	4,060	4,060
May	4,600	4,600	4,600	4,600
June	4,825	4,825	4,825	4,825
TOTAL:	52,560	52,560	52,560	52,560

BLOCK # 2

Delivery Period	2001	2002	2003	2004
Month				
May (15-31)	2,240	2,240	2,240	2,240
June	3,960	3,960	3,960	3,960
July	4,090	4,090	4,090	4,090
August	4,940	4,940	4,940	4,940
September	4,400	4,400	4,400	4,400
October (01-14)	566	556	556	566
TOTAL:	20,196	20,196	20,196	20,196

(AUTHENTICATED COPY)

Contract No. DE-MS79-87BP92411

SALE AND EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF BURBANK

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Section Page

Exhibit A (Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions)..... 8

Exhibit B (General Contract Provisions Form PSC (SW-1))..... 8

Exhibit C (Plan of Delivery)..... 8

Exhibit D (Minimum Monthly Energy Distribution)..... 8

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This SALE AND EXCHANGE AGREEMENT, executed as of January 28, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF BURBANK, CALIFORNIA (Burbank), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Burbank is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Burbank, the City of Glendale (Glendale), the City of Pasadena (Pasadena), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which provides, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Burbank, Glendale, and Pasadena; and

WHEREAS this Agreement and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Burbank desires to purchase and Bonneville desires to sell surplus firm capacity with energy under the terms specified herein; and

WHEREAS Bonneville and Burbank also desire to enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Term.

This Agreement, when executed, shall become effective at 2400 hours January 31, 1988, and shall terminate at 2400 hours on April 15, 2008; provided, however, that no power sales may occur subsequent to January 31, 2008. All obligations incurred hereunder shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

2(a) "Agreement" means this sale and exchange agreement between Bonneville and Burbank.

2(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

2(c) "Contract Demand" means the maximum hourly rate of delivery for surplus firm power when this Agreement operates as a sale, or for capacity when this Agreement operates as an Exchange. This amount is 9 MW for Block 1 and 9 MW for Block 2, and may be modified by Burbank pursuant to section 4. However, Contract Demand, when used in subsection 7(d), shall mean 18 MW, as may be modified by Burbank pursuant to section 4.

2(d) "Contract Year" means the year beginning at 2400 hours on June 30 and ending at 2400 hours the following June 30.

2(e) "Embedded Transmission Costs" means a charge equal to the Nonfirm Rate portion of Bonneville's IS-87 Southern Intertie Transmission Rate Schedule or successor rate to the extent Burbank uses the Pacific Northwest-Pacific Southwest DC Intertie to provide Supplemental Energy to Bonneville; provided, however, that if the Nonfirm Rate portion of IS-87 or successor rate is terminated prior to the expiration of this Agreement, the Parties agree to use an equivalent substitute value calculated using the same methodology Bonneville used to derive the Nonfirm Rate portion of IS-87. Embedded Transmission Costs also shall include a charge equal to Bonneville's ET-87 Energy Transmission Rate Schedule or successor rate to the extent Burbank provides Supplemental Energy either generated from its resources located outside of Los Angeles County or delivered to Burbank's points of delivery located outside of Los Angeles County.

2(f) "Energy Account" means an account consisting of (i) monthly totals of the amount of Peaking Replacement Energy and Exchange Energy obligated to be delivered to Bonneville during each month, the delivery of which energy Bonneville has declined pursuant to

the provisions of paragraph 7(e)(1), and (ii) the value of such declined energy for each month converted to mills/kWh pursuant to paragraph 7(e)(4). For each month there will be two values in the Energy Account: a total amount of energy declined and the value of such energy in mills/kWh.

2(g) "Exchange" means the capacity for energy exchange terms and conditions as described in this Agreement.

2(h) "Exchange Energy" for Block 1 as defined in subsection 5(a) means the energy Burbank is obligated to deliver to Bonneville in equal weekly increments throughout the year in Exchange for Bonneville deliveries of capacity on an annual basis. Exchange Energy for Block 2 as defined in subsection 5(b) means the energy Burbank is obligated to deliver to Bonneville during the period November 16 through April 15 in exchange for Bonneville making available capacity during the preceding May 15 through October 14 period.

2(i) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie transmission lines cross the Nevada-Oregon border.

2(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission capacity due to physical limitations, or (ii) the physical transmission capacity of the DC Intertie is reduced to zero for a period of time which is less than 24-consecutive hours.

2(k) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Burbank during periods when this Agreement operates as an Exchange or capacity sale pursuant to Section 12.

2(l) "Peaking Replacement Energy" means an amount of energy which Burbank is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

2(m) "PNW Coordination Agreement" means the contract among Bonneville and Pacific Northwest (PNW) generating entities, providing for coordinated operation of resources, designated as Contract No. 14-03-48221, as amended or replaced.

2(n) "Supplemental Energy" means the energy Burbank is obligated to make available as a purchase option for Bonneville, pursuant to section 7.

2(o) "Total Incremental Cost" means incremental fuel cost, incremental operation and maintenance, generating unit start-up cost, transmission losses incurred by Burbank in delivering Supplemental Energy to the Point of Delivery, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Burbank in supplying Supplemental Energy to Bonneville that would not otherwise have been incurred.

2(p) "Total Outage" means the physical transmission capacity of the DC Intertie is reduced to zero, whether planned or unplanned, for a period of time which equals or exceeds 24-consecutive hours.

2(q) "UIC" means any unrecoverable incremental costs beyond normal operations incurred by Burbank in generating or acquiring Supplemental Energy for which Bonneville rescinds its request pursuant to paragraph 7(c)(3). UIC includes, but is not limited to, direct costs, penalties, cancellation fees for fuel commitments, transmission services, or unrecoverable energy purchases, but excludes general engineering, scheduling, and administrative charges. UIC shall not include costs incurred by Burbank to the extent that Burbank is able to make use of such Supplemental Energy and in doing so mitigates costs it has incurred or avoids costs it would otherwise have incurred.

2(r) "Workday" means each day which both Bonneville and Burbank observe as a regular workday.

3. Exhibits.

Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), General Contract Provisions (Form PSC (SW-1)) (Exhibit B), Plan of Delivery (Exhibit C), Minimum Monthly Energy Distribution Tables for Burbank (Exhibit D), and Operating Procedures (Exhibit E) are attached hereto and hereby made a part of this Agreement.

4. Option for Burbank to Increase Purchase.

Not later than June 1, 1988, Burbank, Glendale, and Pasadena may, upon written notice, increase their power purchase by a total of 60 MW, or more, if Bonneville determines power is available for this purpose. To the extent that any such increase results in an increase for Burbank pursuant to this Agreement, then that increase shall become effective for the Contract Year beginning at 2400 hours on June 30, 1988, and shall be distributed equally to Blocks 1 and 2 for both the surplus firm power sale and Exchange under this Agreement. This Agreement shall be amended as necessary to reflect such increase.

5. Surplus Firm Power Sale.

5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Burbank shall purchase 17,939 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Burbank shall purchase during each Contract Year 43,362 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Burbank shall purchase during each Contract Year while this Agreement remains a power sale, 47,304 MWh of surplus firm energy.

5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Burbank shall purchase 16,524 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing until 2400 hours on June 30, 1992, Burbank shall purchase 5,076 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, and continuing until 2400 hours on October 14, 1992, Burbank shall purchase 12,593 MWh of surplus firm energy. Beginning at 2400 hours on May 14, 1993, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Burbank shall purchase 18,176 MWh of surplus firm energy.

5(c) Adjustments to Amount of Power.

The above MWh quantities for Burbank shall be adjusted as necessary to account for any increase pursuant to section 4. However, in the event of a partial Contract Year power sale for Block 1, or in the event of a partial May 15 through October 14 power sale for Block 2, Burbank shall purchase the appropriate monthly amounts of surplus firm energy under Block 1 and under Block 2 as shown in the applicable plan of delivery for such Contract Year pursuant to subsection 5(e). Burbank may increase the energy scheduled for purchase from Bonneville for any month under the then-current plan of delivery, if such energy is available as determined by Bonneville for such purpose. Such increases shall not affect the plan of delivery, the minimum monthly energy delivery in any future months during such Contract Year, nor shall any such increase affect the take-or-pay energy amount in any future Contract Year.

5(d) Rates of Delivery.

The maximum hourly rates of delivery for surplus firm power shall be 9 MW from October 15 through May 14 and 18 MW from May 15 through October 14, as may be modified by Burbank's option to increase pursuant to section 4.

5(e) Distribution of Monthly Amounts.

Prior to January 1 of each year, Burbank shall submit a plan of delivery to Bonneville showing the distribution of the monthly amounts of energy for the following 4 Contract Years in the form represented by Exhibit C. Burbank shall distribute the monthly amounts of energy within the limits indicated in Exhibit D.

5(e)(1) If requested by Burbank, Bonneville shall consult with Burbank at the time such plans of delivery are being prepared. Bonneville will share its most recent information on its ability to serve Burbank with a power sale for the following 4 Contract Years and any other

considerations that may relate to the plans of delivery. Bonneville shall include such plans of delivery in its PNW Coordination Agreement planning.

5(e)(2) The Parties shall rely upon the most recent plan of delivery submitted to Bonneville for the amount of energy to be delivered in the upcoming July. Bonneville shall notify Burbank at the earliest opportunity, but not later than August 15, if other than that most recent proposed plan of delivery shall become effective for the balance of the Contract Year. Unless otherwise agreed by the Parties, notwithstanding the limits indicated in Exhibit D, the total of the monthly amounts Bonneville shall deliver during July and August shall equal the 2-month July and August total energy amount specified in the plan of delivery ultimately adopted for use during that Contract Year; provided, however, that in the event that Burbank is unable to receive the minimum amount of energy during August due to the timing of such notice, then the Parties shall adjust deliveries as necessary prior to November 16 to provide for any energy not received during August.

5(e)(3) If Bonneville adopts a plan of delivery other than the most recent plan of delivery submitted, Bonneville shall adjust the adopted plan of delivery to reflect the most recent Intermountain Power Project scheduled maintenance outages.

5(f) Distribution of Weekly Amounts.

Within any month, Burbank shall not take more than 135 percent of that month's average weekly amount in any Calendar Week. Such average weekly amount shall be equal to the total MWh for that month as specified in the applicable plan of delivery, divided by the number of days in that month, and multiplied by 7.

5(g) Operational Flexibility.

Burbank may request changes of up to 5 percent of any monthly amount of energy to be made available under the Agreement, with no less than 2 months' advance written notice. Such changes shall not be unreasonably denied by Bonneville, and the ability to make such changes shall be at no additional cost to Burbank. The effect of such changed monthly amount on subsequent monthly amounts of energy shall be included in this notice; provided, however, that changes in monthly amounts purchased hereunder shall not be reduced below the minimum monthly amounts of energy specified in Exhibit D, unless mutually agreed to by the Parties.

6. Conversion to the Exchange.

The sale of surplus firm power shall convert to the Exchange if Bonneville has a surplus firm energy insufficiency under the

conditions described in this section; provided, however, that Burbank shall have the option to either: (i) remain in the power sale mode until after other similar long term sale and exchange agreements executed with parties outside of the Pacific Northwest region for which initial deliveries shall commence after January 1, 1988, have been converted to an exchange; or (ii) convert to the Exchange prior to the conversion of such other similar long term sale and exchange agreements. Burbank shall exercise its option within 14 days after Burbank receives Bonneville's written notice that it will be converting this Agreement or such other similar agreements to an exchange.

6(a) Preliminary Notice.

6(a)(1) If Bonneville determines in the PNW Coordination Agreement planning process that there is a possibility of insufficient surplus firm energy to satisfy the surplus firm energy obligation to Burbank in the next Contract Year, Bonneville shall provide written notice to Burbank as soon as possible. Following this notice, the Parties may, upon mutual agreement, begin the Exchange at 2400 hours on May 14 or on a subsequent date prior to 2400 hours on June 30 of the then-current Contract Year.

6(a)(2) If Bonneville determines in the planning process that there is a certainty of insufficient surplus firm energy for the next Contract Year, Bonneville shall provide written notice to Burbank as soon as possible, but not later than June 15. In this event, regardless of the extent to which PNW system refill occurs, the Exchange shall begin at 2400 hours on June 30. Burbank's Exchange Energy obligation for Block 2 shall be adjusted to account for a start date of July 1 rather than May 15.

6(b) Final Notice.

If the Exchange does not begin pursuant to subsection 6(a), then the provisions of this subsection apply. The completion of PNW Coordination Agreement planning and the adoption by Bonneville of a particular plan of delivery for Burbank shall occur after July 31. Bonneville shall provide written notice to Burbank as soon as possible after July 31, but not later than August 15, whether service at the Contract Demand shall continue as a power sale or convert to the Exchange. If such notice specifies a conversion to the Exchange, then the Exchange shall begin no sooner than 14 days after the date of receipt of such notice by Burbank. Conversion to the Exchange shall be effective for the remainder of the Contract Year from the time specified in Bonneville's notice to Burbank, or as provided for in subsection 6(c). Burbank's Exchange Energy obligation shall be adjusted to account for the start date specified in the notice rather than May 15.

6(c) Reversion to Power Sale.

After conversion to the Exchange, whenever Bonneville determines that it has sufficient surplus firm energy to deliver the amounts of surplus firm power specified in subsections 5(a) and 5(b) for the ensuing Contract Year, deliveries under this Agreement shall revert to the surplus firm power sale pursuant to section 5, unless Burbank has provided written notice to Bonneville which describes a contract offer to acquire a resource to replace the energy no longer available from Bonneville due to the conversion to the Exchange. Such notice shall include the amount of energy to be acquired and the term of the proposed acquisition. Bonneville shall respond as follows:

Bonneville shall, within 21 days of receipt of such notice, notify Burbank as to whether this transaction shall revert to the power sale for the duration of Burbank's proposed energy acquisition. If this transaction is to revert to the power sale, Bonneville shall notify Burbank of the basis for the reversion, and such power sale shall begin by the later of (1) 31 days from receipt by Bonneville of Burbank's notice, or (2) the effective date of energy deliveries pursuant to Burbank's proposed acquisition, and shall continue for the duration of Burbank's acquisition, subject to the provisions of section 12. If Bonneville elects not to have the transaction revert to the power sale, then Bonneville shall waive its right to revert to the power sale for the duration of Burbank's contractual commitment for the proposed energy acquisition. Prior to the termination of Burbank's acquisition contract, Bonneville shall, upon written notice of at least 30 days, have the right to revert to the power sale as described in section 5 at the termination of Burbank's acquisition.

6(d) The notice provisions of subsections 6(a) and 6(b) shall apply to reversion from Exchange to power sale, as well as the conversion from power sale to Exchange, except as may be modified by the provisions of subsection 6(c).

7. Capacity For Energy Exchange.

Upon conversion to the Exchange, Bonneville shall make 9 MW of capacity available to Burbank for Block 1 on an annual basis and 9 MW of capacity for Block 2 from May 15 through October 14 each year, as may be modified by Burbank's option to increase pursuant to section 4. Burbank shall be obligated to deliver Peaking Replacement Energy to Bonneville during these periods of capacity deliveries as specified in subsection 7(a). In Exchange for Bonneville deliveries of capacity, Burbank shall deliver Exchange Energy and make available Supplemental Energy to Bonneville, as specified in subsections 7(b) and 7(c).

7(a) Deliveries of Capacity and Peaking Replacement Energy.

At times when the Exchange is in effect, Bonneville shall make available to Burbank capacity in an amount up to the Contract Demand each hour, up to 10 hours times the Contract Demand each day Monday through Saturday, including holidays, not to exceed 50 hours times the Contract Demand each week. Burbank shall be obligated to deliver to Bonneville Peaking Replacement Energy for the amounts of Peaking Energy delivered to Burbank by 2400 hours on the day following the Peaking Energy delivery, except as provided in subsection 7(e). Return of Peaking Replacement Energy during any hour shall not exceed 100 percent of the Contract Demand in any hour, unless otherwise mutually agreed by the parties.

7(b) Exchange Energy.

Burbank shall be obligated to deliver Exchange Energy to Bonneville as provided herein. The amount of such energy provided each Contract Year shall equal the exchange ratio in kWh/kW for each block of capacity, multiplied by the Contract Demand in kilowatts for each block of capacity. For Block 1, the exchange ratio is 2,536 kWh/kW; for Block 2, the exchange ratio is 975 kWh/kW. Exchange Energy for Block 1 shall be delivered in equal weekly increments throughout the year and Exchange Energy for Block 2 shall be delivered in equal weekly increments from November 16 through April 15, except as provided in subsection 7(e). Such equal weekly increments shall be adjusted as necessary to account for an uneven number of weeks during any Exchange Energy delivery period. In the event of a partial Contract Year of capacity deliveries, the amount of Exchange Energy which Burbank is obligated to deliver to Bonneville shall be reduced on a pro rata basis to account for such partial Contract Year.

7(c) Supplemental Energy.

7(c)(1) Burbank shall be obligated to make Supplemental Energy available to Bonneville during each November 16 through April 15 while this Agreement operates as an Exchange. The total amount of such energy provided each Contract Year shall equal the supplemental ratio in kWh/kW multiplied by the Block 2 Contract Demand in kilowatts of capacity. The supplemental ratio is 1,200 kWh/kW. Bonneville may elect to purchase up to the maximum amount of Supplemental Energy available to Bonneville in any Contract Year by serving a notice to Burbank not less than 2 months prior to the desired delivery date, or on shorter notice if agreed to by Burbank. Bonneville may issue additional notices during any Contract Year for amounts of Supplemental Energy not previously requested in a notice. Any such notice shall specify the amount of Supplemental Energy desired by Bonneville and provide a

nonbinding proposed schedule for deliveries of Supplemental Energy. Burbank shall promptly notify Bonneville if such proposed schedule is unacceptable to Burbank and the reasons therefor. Burbank shall not unreasonably deny Bonneville's proposed schedule. In the event that the Parties are unable to agree on a proposed schedule, then the requested Supplemental Energy shall be delivered in equal hourly increments during the delivery period specified in Bonneville's notice and during the hours specified in paragraph 7(d)(3). Bonneville and Burbank shall finalize the schedule for deliveries of weekly blocks of Supplemental Energy within 15 Workdays of receipt by Burbank of Bonneville's notice. Deliveries of Supplemental Energy are subject to Burbank's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Burbank's generation or transmission capability. In the event of any such constraints, Burbank shall reschedule such deliveries in a timely manner. In the event of an extended generation constraint, Bonneville may request an alternate available source for Supplemental Energy at another agreed upon price, until such time as the generation constraint is removed.

7(c)(2) Within 15 Workdays of receipt of Bonneville's notice requesting to make available Supplemental Energy, and prior to committing to obtain Supplemental Energy, Burbank shall inform Bonneville of probable resources available, including the estimated price of the lowest cost sources of Supplemental Energy available for purchase, the estimated Total Incremental Cost from such sources, and the UIC for such resources. Burbank shall revise such estimated price, Total Incremental Cost, and UIC if conditions change substantially during the remaining days of the notice period described in paragraph 7(c)(1). If Burbank determines that the UIC from such sources will exceed 4.5 mills, as escalated pursuant to subsection 9(c), it shall notify Bonneville, and Bonneville shall have the option of either: (1) raising such maximum rate for UIC; (2) relieving Burbank of its obligation to provide Supplemental Energy; or (3) obligating itself to purchase Supplemental Energy. Bonneville shall make this choice in a timely manner. Burbank shall use best efforts to mitigate UIC, but unless earlier notification by Burbank and Bonneville's selection of its option to raise the maximum rate for UIC has occurred, Bonneville's obligation for the amount of energy specified in its notice of rescission shall not exceed 4.5 mills/kWh as escalated pursuant to subsection 9(c).

7(c)(3) Bonneville shall pay Burbank any applicable Embedded Transmission Costs plus 115 percent of Burbank's Total Incremental Cost for providing Supplemental Energy. Bonneville may rescind a notice requesting Supplemental Energy not later than 0930 hours of the Workday immediately preceding the day when such Supplemental Energy was to begin to be provided to Bonneville, and pay Burbank any UIC incurred by Burbank in response to Bonneville's previous request for such energy. Any decision to rescind a notice requesting Supplemental Energy shall apply to the total amount of MWh of Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1); provided, however, that Bonneville can rescind a portion of the Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1) if Bonneville agrees to pay any new UIC resulting therefrom.

7(c)(4) Bonneville shall submit schedules for the delivery of Supplemental Energy pursuant to the provisions of paragraph 7(c)(1) and section 10. Burbank shall not unreasonably withhold its agreement with such schedules, and Burbank shall deliver weekly amounts of Supplemental Energy by the end of each Calendar Week during the period of deliveries pursuant to the mutually agreed upon schedules for the delivery of Supplemental Energy.

7(d) Delivery Limitations.

7(d)(1) May 15 through October 14.

Unless limited by Bonneville, Burbank shall complete each Calendar Week's deliveries of Exchange Energy by the end of such Calendar Week. The maximum rate of delivery for Peaking Replacement Energy plus Exchange Energy shall be 100 percent of the Contract Demand. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account. Bonneville may limit the delivery rate for Peaking Replacement Energy plus Exchange Energy to not less than 60 percent of Contract Demand for the Exchange during the period May 15 through October 14. To the extent that Bonneville restricts the delivery on any hour, the restricted quantity of Peaking Replacement Energy and Exchange Energy may either be delivered by Burbank on hours other than the hours specified in paragraph 7(d)(3), or be delivered on the next available normal delivery hour when Bonneville can accept such energy. The Parties may agree to delay the delivery beyond the Calendar Week of delivery, or the Parties may agree to place such energy into the Energy Account, as described in paragraph 7(e)(1).

7(d)(2) November 16 through April 15.

Hourly rates of delivery shall be as mutually agreed upon by Bonneville and Burbank. However, during the period November 16 through April 15, during any hour the total rate of delivery for Exchange Energy plus Supplemental Energy plus Peaking Replacement Energy shall not exceed 250 percent of the Contract Demand, unless mutually agreed to by Bonneville and Burbank. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account.

7(d)(3) Normal Delivery Hours for Peaking Replacement and Exchange Energy.

Although deliveries of Peaking Replacement Energy and Exchange Energy may occur during other hours, the normal delivery hours are as follows:

2200 hours on Monday to 0800 hours on Tuesday
2200 hours on Tuesday to 0800 hours on Wednesday
2200 hours on Wednesday to 0800 hours on Thursday
2200 hours on Thursday to 0800 hours on Friday
2200 hours on Friday to 0800 hours on Saturday
2200 hours on Saturday to 0800 hours on Monday.

7(e) Conditions for Energy Account and Cash-Out of Peaking Replacement and Exchange Energy.

7(e)(1) Declinations of Peaking Replacement Energy and Exchange Energy.

Bonneville may decline deliveries of either Peaking Replacement Energy or Exchange Energy in whole or in part. Bonneville shall provide Burbank with notice by 1400 hours on the Thursday prior to each Calendar Week. Such notice shall specify whether Bonneville will require the delivery of such energy in whole or in part for the next Calendar Week and shall specify the amount of energy which Bonneville declines. To the extent that Bonneville declines the deliveries, the monthly total of such declined energy and its value converted to mills/kWh pursuant to paragraph 7(e)(4) shall be entered into the Energy Account.

7(e)(2) Withdrawals from the Energy Account.

Bonneville may request to withdraw energy from the Energy Account during a Calendar Week and shall provide Burbank with notice by 1400 hours on the Thursday prior to such Calendar Week. Such notice shall specify the quantity of

energy to be withdrawn and the rate of delivery for such energy. However, in addition to other deliveries by Burbank pursuant to this Agreement, the maximum rate of withdrawal from the Energy Account shall not exceed the Contract Demand on any hour, unless mutually agreed. Burbank shall provide such requested energy to Bonneville during the next Calendar Week, subject to Burbank's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Burbank's generation or transmission capability. The value for energy withdrawn from the Energy Account shall be converted to kWh as determined pursuant to paragraph 7(e)(4) and shall be withdrawn on a first-in-first-out basis. To the extent that the value for withdrawn energy is greater than the value for declined energy determined pursuant to paragraph 7(e)(1), Bonneville shall pay Burbank an amount equal to the difference between the values for withdrawn and declined energy multiplied by the kWh withdrawn. To the extent that the value for withdrawn energy is less than the value for declined energy determined pursuant to paragraph 7(e)(1), Burbank shall pay Bonneville an amount equal to the difference between the values for declined and withdrawn energy multiplied by the kWh withdrawn. Each party shall pay the other pursuant to the provisions of section 8. If mutually agreed, withdrawn energy may be provided on hours other than those specified in paragraph 7(d)(3).

7(e)(3) Cash-Out of Energy in the Energy Account.

Bonneville shall maintain the Energy Account. The Energy Account shall contain monthly totals of (i) the declined energy remaining at the end of each calendar month, and (ii) the value of such energy converted to mills/kWh pursuant to paragraph 7(e)(4). Any monthly total of energy which remains in the Energy Account longer than 11 months shall be cashed out pursuant to subsection 9(b) at the cash-out price at the time the energy was entered into the Energy Account. No more than one monthly total of energy shall be cashed out on any monthly bill rendered to Burbank. Burbank shall pay Bonneville pursuant to the cash-out terms specified in subsection 9(b), and shall be relieved of any obligation thereafter to provide such monthly total of energy to Bonneville.

7(e)(4) Determination of Value for Energy Entered into Energy Account and Withdrawn from Energy Account.

Following receipt of its gas bill each month, Burbank shall provide Bonneville with a copy of a portion of such

bill which shows the dollars per dekatherm paid by Burbank for the total of all gas purchases for that month. Bonneville shall convert this amount to dollars per Btu and apply this ratio to an agreed-upon heat rate of 10,000 Btu per kWh to determine the value in mills per kWh for entries into and withdrawals from the Energy Account during the following month. To the extent that gas is not available or is no longer a significant fuel source for generation by Burbank, the Parties shall negotiate: (i) an alternate significant fuel source which is used by Burbank for generation; and (ii) a methodology to derive a value in mills/kWh for entries into and withdrawals from the Energy Account. This Agreement shall be amended to implement the results of such negotiation.

7(f) At Burbank's request, the Parties agree to negotiate in good faith mutually agreeable terms and conditions which would allow Burbank to deliver energy to Bonneville's system for later use by Burbank.

8. Payment.

8(a) Payment by Burbank.

Bonneville shall render preliminary and final adjusted monthly bills to Burbank. Burbank shall pay Bonneville by the close of business on the twentieth (20th) day after the date of each such preliminary bill and any adjustments that may occur on the final monthly bill. The date of such bills shall be no earlier than the mailing date of such bills. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Burbank, then the due date shall be the next following business day. Other provisions related to payment of bills shall be in accordance with the General Rate Schedule Provisions attached to this Agreement.

8(b) Payment by Bonneville.

Burbank shall render monthly bills to Bonneville. Bonneville shall pay Burbank by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to payment of bills shall be in accordance with the General Rate Schedule provisions attached to this Agreement.

9. Rates and Cash-Out.

9(a) Surplus Firm Power.

9(a)(1) Initial Demand and Energy Rates.

The initial demand and energy rates for deliveries of power under Block 1 and Block 2 are as follows: $4.60/kilowatt-month (kW-mo.) and 20.5 mills/kWh (includes Intertie adder). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery.

9(a)(2) Rate Adjustment During First 5 Years.

The initial demand and energy rates for the period January 1, 1988, through December 31, 1988, are described in paragraph 9(a)(1). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. The energy rates specified in this paragraph 9(a)(2) include the Intertie adder. The rates for calendar years 1989 through 1992 are as follows:

Calendar Year	Capacity ($/kW-mo.)	Energy (mills/kWh)
1989	4.88	21.73
1990	5.17	23.03
1991	5.48	24.42
1992	5.81	25.88

Subsequent to December 31, 1992, the demand and energy rates shall be adjusted pursuant to paragraph 9(a)(3).

9(a)(3) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

Adjustments under this paragraph begin January 1, 1993. For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. On the effective date of any Bonneville Priority Firm Power (PF) rate adjustment thereafter, the rate for surplus firm power (SL_{new}) shall be adjusted as follows:

$$SL_{new} = SL_n * \frac{PF_{new}}{PF_{prev}}$$

where SL_{new} = The effective surplus firm power demand and energy charges hereunder as adjusted to reflect the change between PF_{new} and PF_{prev}.

SL_n = For the initial adjustment under this paragraph 9(a)(3) the SL_n demand charge

shall be $5.81/kW-mo. and the energy charge shall be 25.88 mills/kWh. For all subsequent adjustments under this paragraph, the values for SL_n shall be the then-current values for the previous SL_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh, in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(b) Cash-out.

Bonneville shall cash out energy pursuant to paragraph 7(e)(3). Burbank shall pay Bonneville for such energy as provided below.

9(b)(1) Initial Cash-out.

The initial level for cash-out shall be 14.9 mills/kWh.

9(b)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any PF rate adjustment after the effective date of this Agreement, the level of the cash-out rate (CO_{new}) shall be adjusted as follows:

$$CO_{new} = CO_n * \frac{PF_{new}}{PF_{prev}}$$

where

CO_{new} = The effective level for cash-out as adjusted to reflect a new PF rate.

CO_n = For the initial adjustment under this paragraph 9(b)(2), CO_n shall be

14.9 mills/kWh. For all subsequent adjustments under this paragraph, the values for CO_n shall be the then-current values for the previous CO_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(c) Maximum Rate for UIC Incurred by Burbank if Bonneville Rescinds a Notice for Supplemental Energy.

9(c)(1) Initial Maximum Rate for UIC.

In accordance with subsection 7(c), the initial rate for UIC is 4.5 mills/kWh for the amount of energy specified in Bonneville's notice of rescission.

9(c)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any Priority Firm Power (PF) rate adjustment after the effective date of this Agreement, the maximum rate for UIC (UIC_{new}) shall be adjusted as follows:

$$UIC_{new} = UIC_n * \frac{PF_{new}}{PF_{prev}}$$

where

UIC_{new} = The effective rate for UIC as adjusted to reflect a new PF rate.

UIC_n = For the initial adjustment under this paragraph 9(c)(2), UIC_n shall be equal to 4.5 mills/kWh. For all subsequent adjustments under this paragraph, the

values for UIC_n shall be the then-current values for the previous UIC_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

10. Scheduling Provisions for Power Sale and Exchange.

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

10(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

10(b) Prescheduled amounts shall be submitted by 0930 hours.

10(c) This subsection 10(c) shall apply only to the power sale portion of this transaction. If Burbank desires to schedule other than that month's average weekly amount of energy for such month in any Calendar Week, Burbank shall notify Bonneville by 1400 hours on the Monday preceding such Calendar Week. Burbank may revise such new weekly amount if Burbank notifies Bonneville by 1400 hours on the Thursday preceding such Calendar Week.

10(d) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts that Burbank anticipates it will schedule from Bonneville each day for the following 10 days. Burbank shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Burbank or Bonneville to schedule such amounts.

10(e) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such changes

shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

11. Transmission Limitation.

In the event of an interruption of deliveries by either Party due to a DC Intertie outage, the following provisions shall apply.

11(a) Relief Remedies During Periods of Total Outage.

The Parties shall be relieved of obligations as follows.

11(a)(1) Conditions for Capacity Payment Relief.

The following conditions must be met each Contract Year for relief to be given as described in paragraph 11(a)(2): (i) the duration of a single Total Outage exceeds 360-consecutive hours, in which case relief is provided for the remainder of such Total Outage only; or (ii) the sum of all Total Outages for the Contract Year exceeds 720 hours, excluding Total Outages, if any, for which relief was given pursuant to item (i) above.

11(a)(2) Determination of Capacity Payment Relief.

For the duration of the Total Outages which occur subsequent to the occurrence of relief as described in paragraph 11(a)(1), Burbank shall receive a capacity credit in the form of a reduction in the demand rate per kW-mo. calculated by determining such duration of the Total Outage during the billing month, divided by the total number of hours in that month.

11(a)(3) Energy Payment Relief During Power Sale.

Without regard to the duration of a Total Outage, if Burbank is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Burbank shall be relieved of its obligation to pay for such amounts of energy. To the extent that Burbank is unable to receive energy during any month, the monthly minimum take-or-pay energy specified in the applicable plan of delivery shall be reduced by an amount of energy determined as follows: a ratio shall be calculated, the numerator being the number of hours of Total Outage during the month that Burbank is unable to receive energy, and the denominator being the total number of hours in that month. This ratio is then multiplied by the monthly energy specified in the applicable plan of delivery to determine such amount of energy. This amount of energy shall be subtracted from such monthly energy to determine the revised monthly

amount for that month. The total take-or-pay energy for Block 1, or Block 2 if applicable, as specified in Exhibit D, shall be reduced by the amount of energy as calculated above.

11(a)(4) Energy Payment Relief During Exchange.

11(a)(4)(A) For Total Outages which occur subsequent to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Burbank's obligation to deliver Peaking Replacement Energy owed to Bonneville for previous capacity delivered by Bonneville, and Supplemental Energy requested by Bonneville pursuant to subsection 7(c) remain. Burbank's obligation to deliver Exchange Energy associated with a Total Outage up to one year remains, but, at Bonneville's option, either: (i) Burbank shall deliver such energy to Bonneville subject to mutually agreed upon schedules following the end of the Total Outage and Bonneville shall pay Burbank's Total Incremental Cost for the first 3 months of such obligation and 115 percent of Burbank's Total Incremental Cost for the following 9 months; or (ii) Burbank shall be relieved of its obligation to deliver such energy.

11(a)(4)(B) For Total Outages which occur prior to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Burbank shall reschedule deliveries of Peaking Replacement Energy, Exchange Energy, and Supplemental Energy which Burbank is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the Total Outage, or at other times as mutually agreed by the Parties.

11(b) Relief Remedies During Periods of Partial Outage.

11(b)(1) Relief Remedies During the Power Sale.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue deliveries under this Agreement. The Parties also shall curtail pro rata on an hourly basis all agreements executed on or before January 1, 1988, for firm energy or capacity based on reductions of available transmission capacity, and the Parties shall

afford this Agreement precedence in transmission over agreements executed after January 1, 1988 for firm energy or capacity. If Burbank is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Burbank shall be relieved of its obligation to pay for such amounts of energy.

11(b)(2) Relief Remedies During the Exchange.

During the Exchange, or during any period of the power sale when Bonneville has restricted surplus firm energy deliveries pursuant to section 12 and is delivering capacity only, the following provisions shall apply.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue or reschedule deliveries under this Agreement. The Parties shall curtail all agreements for firm capacity without energy or deliveries of exchange energy executed prior to January 1, 1988, pro rata on an hourly basis, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over deliveries of capacity or exchange energy pursuant to agreements executed after January 1, 1988. Burbank shall reschedule interrupted or curtailed deliveries of Peaking Replacement Energy, Exchange Energy and Supplemental Energy which Burbank is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the interruption or curtailment, or at other times and under conditions as mutually agreed by the Parties.

12. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of 16 U.S.C. § 837 (1984) (P.L. 88-552), and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to those provisions, Bonneville shall have the right to restrict all or a portion of the capacity or energy if such capacity or energy is needed to meet the capacity or energy requirements, as the case may be, in the PNW. Such restrictions shall be limited in amounts and duration to cover the projected need specified in the written notice which Bonneville shall provide to Burbank. Such written notice shall specify the date on which a period of restriction begins and the date on which such period of restriction is projected to end. The sale of surplus firm power shall resume pursuant to the applicable plan of delivery for the remainder of the then-current Contract Year after expiration of the period of restriction except as described in the immediately following sentence. If a projected period of restriction exceeds 2 months' duration, Burbank may make other arrangements for energy for the remainder of such Contract Year if Burbank has entered into a contractual commitment with a third party as a direct result of Bonneville's prior notice of restriction, and Bonneville has received Burbank's written notice of such arrangements not later than 10 days prior to the projected end of such period of restriction.

During any period that Bonneville continues to have surplus firm energy on a planning basis, but Bonneville restricts the delivery of energy as provided above, Bonneville shall make available capacity at the Contract Demand and, in the event of a partial energy restriction, a pro rata amount of energy. Prior to the effective date of the restriction, Burbank shall give notice to Bonneville of the amount of capacity made available by Bonneville that Burbank desires for the anticipated duration of the restriction. In such notice, Burbank may reduce the amount of capacity it desires for the anticipated period of restriction below the Contract Demand, with no change in the rate per kW-mo. of capacity specified in section 9; provided, however, that if Burbank reduces the amount of capacity it desires during a period of restriction to zero, and the reduction to zero capacity occurs on any day other than the last day of a month, then Bonneville shall make a pro rata reduction in the rate per kW-mo. of capacity. Terms for the delivery of such capacity and for the cash-out or delivery of Peaking Replacement Energy shall be as provided in this Agreement.

13. Points of Delivery.

13(a) Points of Delivery.

The point of delivery for all deliveries to Bonneville pursuant to this Agreement is NOB.

13(b) Other Pacific Southwest Points of Delivery.

Notwithstanding the point of delivery specified in subsection 13(a), at Bonneville's request, Burbank shall deliver energy owed Bonneville to Pacific Southwest points of delivery where Burbank has interconnections and available transmission capacity with Pacific Southwest utilities.

13(c) Costs Incurred to Point of Delivery.

Each Party shall bear its own costs for deliveries to the point of delivery under subsections 13(a) and 13(b); provided, however, that all deliveries of Supplemental Energy by Burbank to Bonneville pursuant to subsection 7(c) shall be excluded from the provisions of this subsection.

14. Limit of Liability.

It is mutually understood and agreed that Burbank's obligations for the payment of monies pursuant to this Agreement are limited to revenues received by Burbank from the sale of electric power and/or

the disposition of assets of Burbank's power generation and transmission facilities.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ James J. Jura
Administrator

Date January 28, 1988

CITY OF BURBANK, CALIFORNIA

By /s/ Alan E. Capon

Title Acting General Manager

Date December 14, 1987

APPROVED AS TO FORM
CITY ATTORNEY
Date 12-7-87
By /s/ Richard W. Marston
Title Sr. Assist. City Atty.

PLAN OF DELIVERY

1. Monthly Amounts of Energy Requested by Burbank Pursuant to Subsection 5(e).

Year / Month	1988	1989	1990	1991
July				
August				
September				
October				
November				
December				
January				
February				
March				
April				
May				
June				

This attachment will be revised each year upon Burbank's submission of new data.

2. Example, assuming 1992 Power Sale.

Upon Burbank's submittal of plans of delivery each year in accordance with subsection 5(e), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations. Assuming energy sufficient to serve Burbank load as a power sale, the plan of delivery to be used is based upon the degree to which the coordinated system refills.

At 2400 hours on July 31, 1992, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will implement the most recent plan of delivery submitted by Burbank. If the system does not refill, such parties will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier "Critical Periods"). This can be shown as follows:

Critical Period	Burbank's Plan of Delivery
1992 - 1995 (refill)	year 1992 from 1992 submittal
1991 - 1994	year 1992 from 1991 submittal
1990 - 1993	year 1992 from 1990 submittal
1989 - 1992	year 1992 from 1989 submittal

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 9 MW DEMAND		BLOCK 2: 9 MW DEMAND		TOTAL MWh
	LF =	MIN. MWh	LF =	MIN. MWh	
J	30% =	2,009			2,009
F	30% =	1,814			1,814
M	40% =	2,678			2,678
A	50% =	3,240			3,240
M	55% =	3,683	May (15-31) 50% =	1,836	5,519
J	55% =	3,564	50% =	3,240	6,804
J	65% =	4,352 1/	50% =	3,348 1/	7,700
A	65% =	4,352 1/	55% =	3,683 1/	8,035 2/
S	65% =	4,212	50% =	3,240	7,452
O	50% =	3,348	Oct. (1-14) 15% =	454	3,802
N	30% =	1,944			1,944
D	30% =	2,009			2,009
TOTAL		37,205		15,801	
TAKE-OR-PAY		43,362 3/		16,524 3/	
BLOCK 1 LF = 55%			BLOCK 2 LF = 50%		

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).
3/ These figures will be increased on July 1, 1992, pursuant to page 2 of this Exhibit D.

(WP-PKLD-3463c)

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 9 MW DEMAND			BLOCK 2: 9 MW DEMAND			TOTAL MWh
	LF	=	MIN. MWh	LF	=	MIN. MWh	
J	30%	=	2,009				2,009
F	30%	=	1,814				1,814
M	40%	=	2,678				2,678
A	50%	=	3,240				3,240
M	55%	=	3,683	May (15-31) 50%	=	1,836	5,519
J	55%	=	3,564	50%	=	3,240	6,804
J	65%	=	4,352 1/	50%	=	3,348 1/	7,700
A	65%	=	4,352 1/	55%	=	3,683 1/	8,035 2/
S	65%	=	4,212	50%	=	3,240	7,452
O	50%	=	3,348	Oct. (1-14) 15%	=	454	3,802
N	30%	=	1,944				1,944
D	30%	=	2,009				2,009
TOTAL			37,205			15,801	
TAKE-OR-PAY			47,304			18,176	
BLOCK 1 LF = 60%				BLOCK 2 LF = 55%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

(WP-PKLD-3463c)

OPERATING PROCEDURES

No operating procedures have been established as of the date of execution of this Agreement.

Prior to conversion to the Exchange, the Parties agree to develop operating procedures which shall be utilized during the Exchange. Such procedures shall include, but are not limited to, determination and verification of Total Incremental Cost, determination and verification of UIC, operating procedures under the Energy Account, and operating procedures during periods of Total Outage and Partial Outage.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in this Agreement.

AUTHENTICATED COPY

Amendatory Agreement No.1
Contract No. DE-MS79-87BP92411

June 14, 1988

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF BURBANK

This AMENDATORY AGREEMENT, executed as of July 6, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF BURBANK, CALIFORNIA (Burbank), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Burbank is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS on January 28, 1988, Burbank and Bonneville executed Contract No. DE-MS79-87BP92411 (Sale and Exchange Agreement), which provides, among other things, for Bonneville to sell surplus firm capacity with energy to Burbank; and

WHEREAS the Sale and Exchange Agreement also provides that Bonneville and Burbank shall enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS in accordance with the provisions of section 4 of the Sale and Exchange Agreement, Burbank has exercised its option to increase the power purchase from 9 MW for Block 1 and 9 MW for Block 2 to 20 MW for Block 1 and 20 MW for Block 2; and

WHEREAS Burbank has requested and Bonneville has agreed that at such time as the power sale converts to an annual and seasonal capacity for energy exchange, the capacity amounts made available by Bonneville will remain at 9 MW for Block 1 and 9 MW for Block 2; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate

transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Effective Date of Amendatory Agreement.

This Amendatory Agreement, when executed, shall become effective at 2400 hours on June 30, 1988.

2. Amendment of Sale and Exchange Agreement.

The Sale and Exchange Agreement, Contract No. DE-MS79-87BP92411, is hereby amended as follows:

(a) Section 4 is deleted and replaced by a new section 4 as follows:

"4. Increase in Power Purchase for Burbank.

Burbank, by letter to Bonneville dated May 20, 1988, elected to increase its power purchase under the Sale and Exchange Agreement from 9 MW for Block 1 and 9 MW for Block 2 to 20 MW for Block 1 and 20 MW for Block 2. Notwithstanding such increase in the power purchase, the capacity amounts made available by

Bonneville under the Exchange shall remain at 9 MW for Block 1 and 9 MW for Block 2.

(b) Subsection 5(a) is deleted and replaced by the following:

"5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Burbank shall purchase 17,939 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Burbank shall purchase during each Contract Year 96,360 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Burbank shall purchase during each Contract Year while this Agreement remains a power sale, 105,120 MWh of surplus firm energy."

(c) Subsection 5(b) is deleted and replaced by the following:

"5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Burbank shall purchase 4,588 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on October 14, 1988, Bonneville shall make available and Burbank shall purchase 26,525 MWh of surplus firm energy.

Beginning at 2400 hours on May 14, 1989, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Burbank shall purchase 36,720 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Burbank shall purchase 40,392 MWh of surplus firm energy."

(d) Exhibit D, which was effective at 2400 hours on January 31, 1988, is deleted and replaced by the attached Exhibit D.

3. Signature Clause The signatories hereto represent that they have been appropriately authorized to enter this Amendatory Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Amendatory Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ Jack Robertson
ACTING Administrator
JUN 29 1988
Date

CITY OF BURBANK, CALIFORNIA

By /s/ Ronald V. Stassi

Title General Manager. P.S.D.

Date July 6, 1988

(VS6-PMC-3732c)

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 20 MW DEMAND		BLOCK 2: 20 MW DEMAND			TOTAL MWh
	LF =	MIN. MWh		LF =	MIN. MWh	
J	30% =	4,464				4,464
F	30% =	4,032				4,032
M	40% =	5,952				5,952
A	50% =	7,200				7,200
M	55% =	8,184	May (15-31)	50% =	4,080	12,264
J	55% =	7,920		50% =	7,200	15,120
J	65% =	9,672 1/		50% =	7,440 1/	17,112
A	65% =	9,672 1/		55% =	8,184 1/	17,856 2/
S	65% =	9,360		50% =	7,200	16,560
O	50% =	7,440	Oct. (1-14)	15% =	1,008	8,448
N	30% =	4,320				4,320
D	30% =	4,464				4,464
TOTAL		82,680			35,112	
TAKE-OR-PAY		96,360 3/			36,720 3/	
BLOCK 1 LF = 55%				BLOCK 2 LF = 50%		

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).
3/ These figures will be increased in 1992, pursuant to page 2 of this Exhibit D.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 1/ 20 MW DEMAND		BLOCK 2: 20 MW DEMAND		TOTAL MWh
	LF =	MIN. MWh	LF =	MIN. MWh	
J	30% =	4,464			4,464
F	30% =	4,032			4,032
M	40% =	5,952			5,952
A	50% =	7,200			7,200
M	55% =	8,184	May (15-31) 50% =	4,080	12,264
J	55% =	7,920	50% =	7,200	15,120
J	65% =	9,672 2/	50% =	7,440 2/	17,112
A	65% =	9,672 2/	55% =	8,184 2/	17,856 3/
S	65% =	9,360	50% =	7,200	16,560
O	50% =	7,440	Oct. (1-14) 15% =	1,008	8,448
N	30% =	4,320			4,320
D	30% =	4,464			4,464
TOTAL		82,680		35,112	
TAKE-OR-PAY		105,120		40,392	
BLOCK 1 LF = 60%			BLOCK 2 LF = 55%		

1/ The total take-or-pay energy amount for Block 1 shall be effective at 2400 hours on June 30, 1992.
2/ July and August in both Blocks have maximum load factors of 75%.
3/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).

SERVICE AGREEMENT
for
POINT-TO-POINT
TRANSMISSION SERVICE
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
TRANSCANADA POWER
a division of
TRANSCANADA ENERGY ~~LIMITED~~ LTD. KJ
CP

1. This Service Agreement, dated as of **_Jan. 22nd/2002_**, is entered into, by and between the Bonneville Power Administration Transmission Business Line (Transmission Provider) and TransCanada Power, a division of TransCanada Energy Limited (Transmission Customer).

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point (PTP) Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff).

3. The Transmission Customer has provided to the Transmission Provider a deposit, if applicable, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.

4. Service under this agreement shall commence on 2400 hours on January 13, 2002, and shall terminate on 2400 hours on January 13, 2032.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit B.

7. The Tariff, Exhibit A (Specifications for Long-Term Firm Point-To-Point Transmission Service), and Exhibit B (Notices) are incorporated herein and made a part hereof. Capitalized terms not defined in this agreement are defined in the Tariff.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(i) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

TRANSCANADA POWER a division of TransCanada Energy ~~Limited~~ **Ltd. KJ**	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ KARL JOHANNSON**	By: **/S/ CLIFFORD C PERIGO**
Name: **Karl Johannson** *(Print/Type)*	Name: Clifford C. Perigo *(Print/Type)*
Title: **Vice President Western Power**	Title: Senior Transmission Account Executive
Date: **Jan. 22nd/2002**	Date:

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EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 1
REQUEST FOR TRANSMISSION SERVICES

Table 1 is not applicable at this time.

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TABLE 2
DIRECT ASSIGNMENT AND USE-OF-FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

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TABLE 3
ANCILLARY SERVICE CHARGES

This Table 3 is subject to the ACS-02 Rate Schedule or successor rate schedules.

		Provided By	Contract No.
1.	**SCHEDULING, SYSTEM CONTROL AND DISPATCH**	Transmission Provider	02TX-10882
2.	**REACTIVE SUPPLY AND VOLTAGE CONTROL**	Transmission Provider	02TX-10882
3.	**REGULATION & FREQUENCY RESPONSE**	As Applicable	02TX-10882
4.	**ENERGY IMBALANCE SERVICE**	As Applicable	02TX-10882
5.	**OPERATING RESERVE - SPINNING RESERVE**	As Applicable	02TX-10882
6.	**OPERATING RESERVE - SUPPLEMENTAL RESERVE**	As Applicable	02TX-10882

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EXHIBIT B
NOTICES

1. **NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT**
Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, First Class mail, by telefax or sent by acknowledged delivery.

If to the Transmission Customer:

TransCanada Power
450, 1st Street SW
Calgary, AB T2P 5H1
CANADA
Attention: Douglas Way
Title: Power Trader
Phone: (403) 920-5038
Fax: (403) 920-2464
E-Mail: doug_way@transcanada.com

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491
Attention: Senior Transmission Account Executive for TransCanada Power – TM/Ditt2
Phone: (360) 418-8293
Fax: (360) 418-8320

2. **NOTICES OF AN OPERATING NATURE**
Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by telefax or sent by First Class mail or acknowledged delivery.

If to the Transmission Customer:

TransCanada Power
450, 1st Street SW
Calgary, AB T2P 5H1
CANADA
Attention: Prescheduling
Phone: (403) 920-2904
Fax: (___) ___-_____

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491
Attention: Real-Time Scheduling
Phone: **EMERGENCY ONLY**
(360) 695-2650
Fax: (360) 418-8740

3. **SCHEDULING AGENT**
Not applicable at this time.

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 01 498160
REQUEST FOR TRANSMISSION SERVICES

1. TERM OF TRANSACTION

Start Date: at 0000 hours on December 1, 2004.

Termination Date: at 0000 hours on April 1, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent
TransCanada Energy Ltd.	John Day Substation (500 kV)	BPA	30,000	COB (500 kV)	BPA	30,000	CISO	TransCanada Energy Ltd.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation 500 kV	COB 500 kV	12/01/04 - 4/01/06: 30 MW	IS-02

4. DESCRIPTION OF POINTS OF INTERCONNECTION

John Day Substation:

Location: The points in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: quantities are to be scheduled

5. **POINTS OF DELIVERY**
California Oregon Border (COB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon Border, where BPA shall make Electric power available for the California Independent System Operator (CISO) hereunder.

Voltage: 500 kV

Metering: quantities are to be scheduled

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None

TRANSCANADA POWER a division of TransCanada Energy Ltd.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ KARL JOHANNSON Karl Johannson Vice President Western Power	By: /S/ CLIFFORD C PERIGO
Name: /S/ CARL CALATONE (Print/Type) Carl Calatone	Name: Clifford C. Perigo (Print/Type)
Title: V.P. Power Strategy	Title: Sr Act Exec.
Date: 3-11-03	Date: 2-20-03

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 01 498159
REQUEST FOR TRANSMISSION SERVICES

1. TERM OF TRANSACTION

Start Date: at 0000 hours on October 1, 2003.

Termination Date: at 0000 hours on April 1, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent
TransCanada Energy Ltd.	John Day Substation (500 kV)	BPA	20,000	COB (500 kV)	BPA	20,000	CISO	TransCanada Energy Ltd.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation 500 kV	COB 500 kV	10/01/03- 4/01/06: 20 MW	IS-02

4. DESCRIPTION OF POINTS OF INTERCONNECTION
John Day Substation:

Location: The points in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: quantities are to be scheduled

5. **POINTS OF DELIVERY**
California Oregon Border (COB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon Border, where BPA shall make Electric power available for the California Independent System Operator (CISO) hereunder.

Voltage: 500 kV

Metering: quantities are to be scheduled

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None

TRANSCANADA POWER a division of TransCanada Energy Ltd.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ Karl Johannson Karl Johannson Vice President Western Power	By: /S/ CLIFFORD C PERIGO
Name: /S/ Carl Calantone (Print/Type) Carl Calantone	Name: Clifford C Perigo (Print/Type)
Title: V. P. Power Strategy	Title: Sr. Act Exec
Date: 3-11-03	Date: 2-20-03

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SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
HERMISTON POWER PARTNERSHIP

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Exhibit A	(Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit B	(Facilities Charges)
Exhibit C	(Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 10th day of May1999, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and Hermiston Power Partnership (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 TERMS AND CONDITIONS

BPA agrees to provide and the Transmission Customer agrees to take and pay for PTP Transmission Services in accordance with the provisions of this Service Agreement and the Open Access Transmission Tariff (Tariff). The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference. BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory

or preferential. BPA and the Transmission Customer agree that Transmission Service provided pursuant to this Service Agreement may be provided under a Commission-approved successor tariff after September 30, 2001, if BPA supersedes the Tariff.

1.2 STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit A and made applicable to that transaction.

1.3 WHOLESALE POWER AND TRANSMISSION RATES SCHEDULES

BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated by this reference.

1.4 FACILITIES CHARGES

All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit B.

1.5 ANCILLARY SERVICES

The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit C.

1.6 TRANSMISSION SCHEDULING PROVISIONS

The Transmission Customer shall schedule transmission transactions in accordance with BPA's Transmission Scheduling Provisions and Procedures as posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPAT

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

This Service Agreement shall be effective on the date executed as written above. Service under this Service Agreement shall commence on the later of: (a) 2400 hours on July 1, 2001 or (b) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades is completed; provided, however, that service may not commence later than the maximum period allowed in the Tariff for extensions for commencement of service. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on June 30, 2021 or (b) 2400 hours on the date of termination established pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 CHARGES FOR TRANSMISSION SERVICE

The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the BPA Wholesale Power and Transmission Rate Schedules. BPA may change the rates that apply to Transmission Service under this Service Agreement pursuant to applicable law.

4.2 BILLING AND PAYMENT

Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and shall be payable in accordance with the Tariff.

4.3 BPA APPROPRIATIONS REFINANCING ACT, PUBLIC LAW 104-134

The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If to Hermiston Power Partnership:

Hermiston Power Partnership
3380 Americana Terrace, Suite 300
Boise, ID 83706
Attention: Mike Elliott, P.E.
Title: Project Manager
Phone: (208) 395-8930
Fax: (208)395-8931

If to BPA:

Bonneville Power Administration
P. O. Box 491
Vancouver, WA 98666-0491
Attention:
Transmission Account Executive for
Hermiston Power Partnership

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified Transmission Service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 INTERCONNECTION WITH OTHER SYSTEMS

Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 GOVERNING LAW

This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3 AMENDMENTS

Except as provided in Articles 1.1, 6.4, and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 TARIFF REVISIONS

In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than 60 days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within 30 days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within 30 days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the

Transmission Service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.5 REVISION OF EXHIBITS

If any changes to Exhibits A, B, or C are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.5.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit A pursuant to this Service Agreement, BPA shall prepare a revised Exhibit A. BPA reserves the unilateral right to amend contiguous point of delivery provisions in Exhibit A of this Service Agreement.

6.5.2 If the Parties agree to change Exhibit B, BPA shall prepare a new Exhibit B. BPA reserves the right to revise Exhibit B annually to reflect changes consistent with the provisions of Exhibit B, section 1.

6.5.3 If the Parties agree to change Exhibit C, BPA shall prepare a new Exhibit C. BPA reserves the right to update the loss factors identified in Exhibit C, section 2, Transmission Loss Factors.

6.6 TEMPORARY LOAD SHIFTS AND MAINTENANCE NOTIFICATION

The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within 4 days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The point of contact for each Party will be designated pursuant to Article 5.2 of this Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within 4 days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.7 SEVERABILITY

In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.8 COMPUTATION OF TIME

To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.9 NO THIRD PARTY BENEFICIARIES

This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.10 WAIVERS

Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.11 SUCCESSORS AND ASSIGNS

This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.12 SERVICE AGREEMENT GOVERNS

In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.13 RELATED AGREEMENTS

6.13.1 System Impact Study and Facilities Study Agreement, Contract No. 98TX-30145;

6.13.2 Construction Agreement, Contract No. 99TX-10238 (under negotiation as of 4/9/99).

6.13.3 Letter of Understanding, Contract No. 99TX-10196 (offered 4/1/99).

6.13.4 Interconnection Agreement, Contract No. 99TX-10236 (BPA intends to offer this agreement prior to the execution of the Construction Agreement)

6.14 ENTIRE AGREEMENT

This Service Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

ARTICLE 7
SIGNATURES

The signatories represent that they are authorized to enter into this Service Agreement on behalf of the Party for whom they sign.

HERMISTON POWER PARTNERSHIP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ RANDOLPH J. HILL	By: /S/ SUSAN E. GARIFO FURST
Name: Randolph J. Hill (Print/Type)	Name: Susan E. Garifo Furst (Print/Type)
Title: Member Management Commmittee	Title: Transmission Account Executive
Date: May 10, 1999	Date: 9 April 1999

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

1. TERM OF TRANSACTION

Start Date: at 2400 hours on June 30, 2001.

Termination Date: The earlier of : (a) 2400 hours on June 30, 2021; or (b) 2400 hours on the termination date established pursuant to Article 3 of this Service Agreement.

2a. SUMMARY OF NETWORK POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party	Scheduling Agent[2/]
Hermiston Power Project	McNary 500 kV [3/]	BPA	See Sect. 3 below	John Day 500 kV	BPA	See Sect. 3 below	BPA	BPA
				Big Eddy 500 kV	BPA	See Sect. 3 below	BPA	BPA
Total Transmission Demand			See Sect. 3 below			See Sect. 3 below		

[1/] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.
[3/] This POI may change to the substation adjacent to the Hermiston Power Project (HPP) if a transmission line connecting HPP to the McNary Substation is built to BPA standards.

2b. SUMMARY OF INTERTIE POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party	Scheduling Agent[2/]
Hermiston Power Partnership	John Day Substation 500 kV	BPA	See Sect 3 below	COB, 500 kV	BPA	See Sect. 3 Below		BPA
	Big Eddy 500 kV	BPA	See Sect 3 below	NOB 1000 kV	BPA	See Sect. 3 below		BPA
Total Transmission Demand			[3/]			[3/] [4/]		

3a. SUMMARY OF INTERTIE POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

(a) July 1, 2001 - June 30 2003

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
John Day Substation 500 kV	308,000	COB 500 kV	308,000
Big Eddy 500 kV	228,000	NOB 1000 kV	228,000
Total Transmission Demand	**536,000**		**536,000**

[1/] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

(a) **July 1, 2003 – June 30, 2021**

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
John Day Substation 500 kV	536,000	COB 500 kV	536,000
Total Transmission Demand	**536,000**		**536,000**

3b. SUMMARY OF NETWORK POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

(a) **July 1, 2001 – June 30, 2003**

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
McNary Substation 500 kV	536,000	John Day Substation 500 kV	308,000
		Big Eddy 500 kV	228,000
Total Transmission Demand	**536,000**		**536,000**

(a) **July 1, 2003 – June 30, 2021**

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
McNary Substation 500 kV	536,000	John Day Substation 500 kV	536,000
Total Transmission Demand	**536,000**		**536,000**

Reservation Fee: The first year of the extension period for commencement of service shall begin on the effective date of the Service Agreement. The first annual nonrefundable reservation fee of $1,218,864 shall be payable within 30 days of the effective date of this Service Agreement. For each subsequent full or partial year of the extension period for commencement of service, the annual nonrefundable reservation fee of $1,218,864 shall be billed within 30 days of the beginning of the subsequent year.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) MCNARY POINT OF INTERCONNECTION

Location: (to be determined from Projects Requirements Diagram (PRD) in the Construction Agreement).

Voltage: 500 kV

Metering: (to be determined from PRD).

(b) JOHN DAY SUBSTATION POINT OF INTERCONNECTION

Location: The point in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: Scheduled quantities

(c) BIG EDDY SUBSTATION POINT OF INTERCONNECTION

Location: The point in the Government's Big Eddy Substation where the Government's Celilo converter station are connected to the 500 kV bus.

Voltage: 1000 kV

Metering: Scheduled quantities

5. POINTS OF DELIVERY

(a) CALIFORNIA – OREGON BORDER (COB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the California Oregon border (COB) where Bonneville shall make Electric Power available for the Transmission Customer hereunder.

Voltage: 500 kV

Metering: Scheduled quantities

(b) NEVADA – OREGON BORDER (NOB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada Oregon border (NOB) where Bonneville shall make Electric Power available for the Transmission Customer hereunder.

Voltage: 1000 kV

Metering: Scheduled quantities

Receiving Control Area: Los Angeles Department of Water and Power

(c) JOHN DAY SUBSTATION:

Location: The point in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: Scheduled quantities

(d) BIG EDDY SUBSTATION

Location: The point in the Government's Big Eddy Substation where the Government's Celilo converter station are connected to the 500 kV bus.

Voltage: 500 kV

Metering: Scheduled quantities

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Hermiston Power Partnership

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE None

8. SHORT-DISTANCE DISCOUNT (SDD)
None

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FACILITIES CHARGES

Specifics of the Transmission Customer's obligation to BPA for the Transmission Customer's future use of BPA's McNary-Roundup right of way, shall be determined in the negotiations of the Construction Agreement, Contract No. 99TX-10238. This Facilities Charges Exhibit will be updated at that time.

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ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL[1/])	98TX-10154
(b)	**Energy Imbalance**	BPA (TBL[1/])	98TX-10154
(c)	**Control Area Reserves for Resources**	BPA (TBL[1/])	98TX-10154
(d)	**Control Area Reserves for Interruptible Purchases**	N/A	
(e)	**Load Regulation**	N/A	
(f)	**Reactive Supply and Voltage Control**	BPA (TBL)	
(g)	**Transmission Losses**	BPA (TBL[1/])	98TX-10154

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) **Transmission Losses Associated with Federal Power**
Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) **Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power**
The Transmission Customer shall compensate BPA for losses BPA incurs when providing Transmission Service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be

[1/] BPA's Transmission Business Line.

determined by multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in section 2; and

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) **Transmission Losses Associated with Delivery Facilities**
Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year [2/] pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) **Notification**

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice for compensating BPA for

[2/] Fiscal Year is defined as the twelve-month period from October 1 through September 30.

transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit C.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate in the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) **Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year**

The Transmission Customer has elected to return Transmission Losses for the period 2400 hours June 30, 2001, through 2400 hours September 30, 2002. The Transmission Customer will return the losses from a single Control Area in the Pacific Northwest, as defined in the Pacific Northwest Electric Power Planning and Conservation Act. The name of that Control Area is BPA.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit C as appropriate, but not more frequently than once in a 12-month period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit C incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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AUTHENTICATED REVISION NO. 11, EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR
LONG-TERM FIRM TRANSMISSION SERVICE

This Revision No. 11 reflects an assignment [1] of transmission service under this Service Agreement from Assignor Hermiston Power Partnership (HPP) to Assignee PPM Energy, Inc. (PPM) [2]and is contingent upon execution of such assignment. This revision decreases HPP's intertie transmission demand by 50 MW at the John Day Substation Point of Interconnection (POI) and at the California-Oregon Border Point of Delivery (POD) for the period January 1, 2005, through December 31, 2005.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2005.
Termination Date: at 2400 hours on June 30, 2021.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

(a) Network POIs and PODs: Hermiston Power Project

Delivering Party (Resource) [3]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party and Scheduling Agent
Hermiston Power Project	McNary (500 kV)	BPA	See §3 below	John Day (500 kV)	BPA	See §3 below	Calpine Energy Services, L.P.
				Big Eddy (500 kV)			

Total Reserved Capacity: See section 3 below.

(b) Intertie POIs and PODs: Hermiston Power Project

Delivering Party (Resource) [3]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party and Scheduling Agent
Hermiston Power Project	John Day Substation (500 kV)	BPA	See §3 below	COB (500 kV)	BPA	See §3 below	Calpine Energy Services, L.P.
	Big Eddy	BPA	See §3 below	NOB	BPA	See §3 below	Calpine

[1] See section 3(b)(1).
[2] See Exhibit A, Table 11, PPM Service Agreement, Contract No. 00TX-10367.
[3] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at time of preschedule.

	(500 kV)			(1000 kV)			Energy Services, L.P.

Total Reserved Capacity: See section 3 below.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

(a) Network POIs and PODs

(1) January 1, 2005 - June 30, 2021

The OASIS Assignment Reference Numbers (ARef) are: 626252 and 420845.

Point(s) of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point(s) of Delivery (Voltage)	Maximum Transmission Demand
McNary Substation (500 kV)	Jan 05 - Feb 05 536,000 Mar 05 - Jun 21 308,000	John Day Substation (500 kV)	Jan 04 - Feb 05: 536,000 kW Mar 05 - Jun 21: 308,000 kW
	Mar 05 - Jun 21 228,000	Big Eddy Substation (500 kV)	Mar 05 - Jun 21: 228,000 kW
Total Maximum Transmission Demand	**536,000**		**536,000 kW**

(b) Intertie POIs and PODs

(1) January 1, 2005 - June 30, 2021

The OASIS Assignment Reference Numbers (ARef) are: 449487, 449490, 449491, 449493, and 596897.

Point(s) of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point(s) of Delivery (Voltage)	Maximum Transmission Demand
John Day Substation (500 kV)	Jan 05 - Feb 05: 486,000[1] Mar 05 - Dec 05: 258,000[1] Jan 06 - Jun 21: 308,000[1]	COB (500 kV)	Jan 05 - Feb 05: 486,000 kW[1] Mar 05 - Dec 05: 258,000 kW[1] Jan 05 - Jun 21: 308,000 kW[1]
Big Eddy (500 kV)	Mar 05 - Jun 21: 228,000	NOB (1000 kV)	Mar 05 - Jun 21: 228,000 kW
Total Maximum Transmission Demand	**536,000[2]**		**536,000 kW[2]**

[1] Reflects an assignment to PPM of 50 MW (see PPM Contract No. 00TX-10367, Exhibit A, Table 11) under Revision No. 11, and excludes any assignment participation under BPA's Pilot Program for Partial Assignment of Transmission Service.

[2] The Maximum Transmission Demand for the period 1/1/05 through 12/31/05 is 486,000 kW.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) Big Eddy Substation Point of Interconnection

Location: the point in the Transmission Provider's Big Eddy Substation where the Transmission Provider's Celilo converter station is connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) John Day Substation Point of Interconnection

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(c) McNary Point of Interconnection

Location: the point in the vicinity of the Transmission Provider's McNary Substation at Bay 7, where the 500 kV facilities of the Transmission Provider and the Transmission Customer are connected;

Voltage: 500 kV;

Metering: Calpine's HPP Substation.

5. POINTS OF DELIVERY

(a) Big Eddy Substation

Location: the point in the Transmission Provider's Big Eddy Substation where the Transmission Provider's converter station is connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB), where Bonneville shall make Electric Power available for the Transmission Customer hereunder;

Voltage: 500 kV;

Metering: scheduled quantities.

(c) **John Day Substation**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(d) **Nevada - Oregon Border (NOB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB) where Bonneville shall make Electric Power available for the Transmission Customer hereunder;

Voltage: 1000 kV;

Metering: scheduled quantities;

Receiving Control Area: Los Angeles Department of Water and Power.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Hermiston Power Partnership.

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

8. **SHORT-DISTANCE DISCOUNT (SDD)**
None.

HERMISTON POWER PARTNERSHIP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ MIKE ROGERS**	By: **/S/ NANCY E MORGAN**
Name: **Mike Rogers** *(Print/Type)*	Name: **Nancy E. Morgan** *(Print/Type)*
Title: **Vice President**	Title: **Transmission Sales Manager**
Date: **1/05/05**	Date: **1/7/05**

(W:\TMC\CT\H P P\Revisions\10154R11A.doc) 11/10/04

Contract No. DE-MS79-94BP94285
05/25/94

AC INTERTIE TRANSMISSION AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP

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This AC INTERTIE TRANSMISSION AGREEMENT, executed June 1, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS Bonneville and PacifiCorp, on August 27, 1982, entered into Contract No. DE-MS79-81BP90424, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract"; and

WHEREAS PacifiCorp and the Western Area Power Administration Sacramento Area Office (Western) have entered into a contract dated September 17, 1992, which, as amended or replaced, is hereinafter referred to as "Western Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to Western; and

WHEREAS PacifiCorp and the City of Redding (Redding) have entered into a contract dated October 19, 1993, which, as amended or replaced, is hereinafter referred to as "Redding Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to the City of Redding; and

WHEREAS Bonneville and PacifiCorp entered into an Intertie Agreement, Contract No. DE-MS79-86BP92299, as amended, effective July 8, 1986, which is hereinafter referred to as " Intertie Agreement", and the Parties have replaced such agreement with Contract No. DE-MS79-94BP94332, which, as amended or replaced, is hereinafter referred to as "AC Intertie Agreement"; and

WHEREAS Bonneville and PacifiCorp have entered into a Letter of Understanding (LOU) dated May 28, 1993, which provides that Bonneville shall under certain circumstances offer PacifiCorp interim and long-term firm transmission contracts providing wheeling for PacifiCorp's Western Sales Agreement and Redding Sales Agreement, and for nonfirm wheeling; and

WHEREAS Bonneville has developed the LTIAP, as defined below, which includes provisions for non-Federal access to the AC Intertie for transactions with Pacific Northwest and California utilities; and

WHEREAS the Parties agree that the terms and conditions of the LOU represent a Joint Venture pursuant to Section 4(b)(1) of the LTIAP; and

WHEREAS consistent with the LOU and in order to facilitate the arrangements provided for in the Western Sales Agreement and the Redding Sales Agreement, Bonneville will provide transmission service in a North-to-South direction from the Points of Interconnection, over the AC Intertie, for deliveries of Electric Power to Western, Redding, and other third parties at the Points of Delivery, and transmission service in a South-to-North direction from the Points of Interconnection, over the AC Intertie, to the Points of Delivery for the delivery of Electric Power to PacifiCorp; and

WHEREAS in accordance with the LOU, Bonneville will provide such access to the AC Intertie for firm and nonfirm transactions up to the Transmission Demand both in a North-to-South and South-to-North direction without regard to the source or ultimate user of services provided under such transactions; and

WHEREAS PacifiCorp and Bonneville desire to provide for such services pursuant to the terms of this Agreement and pursuant to the terms of the LTIAP; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. TERM OF AGREEMENT

This Agreement shall be effective on the Effective Date, and shall continue in effect until the earlier of (1) 2400 hours on December 31, 2018, or (2) the later of the termination date of the Western Sales Agreement or the Redding Sales Agreement. All liabilities incurred under this Agreement are hereby preserved until satisfied. Upon termination of this Agreement, Bonneville will offer to extend such services in an agreement to be executed by the Parties for a period of up to 25 years, based upon Bonneville's then standard terms included in similar agreements, provided that no mitigation charges shall be applied, beyond the applicable FERC-approved Bonneville rates, if PacifiCorp requires such service.

2. DEFINITION AND EXPLANATION OF TERMS

(a) "AC Intertie" means Bonneville's rights in the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line, Bonneville's rights in the Meridian-Malin 500 kV transmission line, Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 10 kilometer 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, improvements, or additions to such facilities.

(b) "Agreement" means this AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285.

(c) "Billing Energy" means the net amount of Electric Energy scheduled in a North-to-South direction and in a South-to-North direction during a month hereunder.

(d) "COB" means the California-Oregon border.

(e) "DC Intertie" means Bonneville's rights in the 1000 kV direct current (DC) transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to the Nevada-Oregon border.

(f) "Demand Charge" means the demand charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(g) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system

related to the disturbances of concern, thereby providing acceptable power system performance.

(h) "Effective Date" means 2400 hours on the date of execution.

(i) "Electric Energy" means electric energy, expressed in kilowatthours.

(j) "Electric Power" or "power" means electric peaking capacity, expressed in kilowatts, Electric Energy, or both.

(k) "Energy Charge" means the energy charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(l) "FCRTS" means the Federal Columbia River Transmission System and other Pacific Northwest facilities over which Bonneville has transmission rights.

(m) "FERC" means the Federal Energy Regulatory Commission, or its successor agency.

(n) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, and amended on April 8, 1993, attached hereto as Exhibit E.

(o) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency, loading condition, or maintenance outage on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce AC Intertie loadings, whether or not all facilities are in service.

(p) "OTC" or "Operational Transfer Capability" means the RTC less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, and Operational Constraints, as determined by Bonneville, resulting from, among other things, line or equipment outages, stability limits, or loopflows.

(q) "Pacific Northwest" is as defined in the LTIAP.

(r) "Points of Delivery" means the points, specified and described in Exhibit C, where Electric Power made available by or on behalf of PacifiCorp shall be delivered by Bonneville.

(s) "Points of Interconnection" means the points, specified and described in Exhibit C, where Electric Power shall be made available by or on behalf of PacifiCorp to Bonneville for transmission over the AC Intertie.

(t) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts existing prior thereto in the electrical utility industry, in the Western Systems Coordinating Council area, or, if there are no such practices, methods, and acts, the practices, methods, and acts, which, in the exercise of reasonable judgment in the light of the facts which were known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(u) "RTC" or "Rated Transfer Capability" means the capability of a transmission line or system to transfer a specified quantity of Electric Power in a prudent and reliable manner.

(v) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville power flows and/or stability studies.

(w) "Transmission Demand" means the maximum amount of Electric Power that Bonneville shall be obligated to transmit during an hour hereunder. Such amount is specified in Exhibit C and shall be changed only upon mutual agreement of the parties.

(x) "Workday" means each day that PacifiCorp and Bonneville jointly observe as a regular workday.

3. EXHIBITS AND INTERPRETATIONS

The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement. This Agreement sets forth the entire agreement of the Parties as of the date of execution. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement. PacifiCorp shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. TRANSMISSION OF ELECTRIC POWER

(a) Subject to the other provisions of this Agreement, Electric Power shall be transmitted by Bonneville on a firm basis from South-to-North and from North-to-South over the AC Intertie, and PacifiCorp shall schedule pursuant to section 7(a) and make available, or arrange to have made available, to Bonneville at the Points of Interconnection the amounts of Electric Power that PacifiCorp determines are available for transmission to the Points of Delivery hereunder for each hour.

(b) The hourly amounts of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand as specified in Exhibit C.

(c) During times when the North-to-South OTC of the AC Intertie is less than the North-to-South RTC, PacifiCorp's reduced net North-to-South scheduling rights shall be an amount determined by multiplying the North-to-South OTC of the AC Intertie by the ratio of PacifiCorp's North-to-South Transmission Demand to the North-to-South RTC of the AC Intertie. During times when the South-to-North OTC of the AC Intertie is less than the South-to-North RTC, PacifiCorp's reduced net South-to-North scheduling rights shall be an amount determined by multiplying the South-to-North

OTC of the AC Intertie by the ratio of PacifiCorp's South-to-North Transmission Demand to the South-to-North RTC of the AC Intertie.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints. The amount of curtailment shall be consistent with Prudent Utility Practice.

(e) PacifiCorp shall be responsible for providing or assuring at its cost the provision of its pro rata share of Remedial Action Schemes required to support the RTC and OTC of the AC Intertie in either the South-to-North or North-to-South direction. Bonneville and PacifiCorp shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. PacifiCorp may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective Control Action is obtained. The level of reliability of the Remedial Action Scheme design on PacifiCorp's system shall be at least equal to the level of reliability employed in the design of the overall AC Intertie Remedial Action Scheme.

(1) PacifiCorp's contribution to the total operational responsibility for this Remedial Action Scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the total RTC of the AC Intertie.

(2) Bonneville shall provide the appropriate control signal or signals to PacifiCorp.

(3) PacifiCorp shall provide the necessary equipment to receive and transmit the control signal or signals to and from PacifiCorp's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions as determined by Bonneville.

(4) In support of its obligations to provide generator dropping for its net North-to-South AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on-line at the time of the Remedial Action Scheme requirement.

(5) Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net North-to-South AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on-line at the time of the Remedial Action Scheme requirement. Such access to PacifiCorp's Mid-Columbia generator dropping capability by Bonneville shall be at no cost to Bonneville.

(6) To the extent that PacifiCorp does not have the capability on-line to provide generator dropping from its Mid-Columbia rights for its net North-to-South AC Intertie schedules, Bonneville shall, to the extent it has available on-line generation, provide generator dropping capability to PacifiCorp at no cost to PacifiCorp.

(7) In support of PacifiCorp's net South-to-North schedules on the AC Intertie, PacifiCorp shall be responsible for making arrangements for any load dropping requirements.

(8) To the extent possible, as determined by Bonneville, Bonneville shall offer to sell Remedial Action Scheme service to PacifiCorp to enable PacifiCorp to meet its obligations under this section 4(e).

(9) Nothing in this section 4(e) shall be construed so as to diminish in any way PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the RTC and the OTC of the AC Intertie in either the North-to-South or South-to-North direction.

(f) When PacifiCorp schedules deliveries pursuant to this Agreement or any agreement for use of AC Intertie capacity entered into pursuant to the LOU, including future Pacific Northwest AC Intertie Capacity Ownership

Agreements, PacifiCorp shall not be required to obtain additional main grid wheeling on Bonneville's system unless insufficient capacity exists in the combined capability of the Midpoint-Malin 500 kV line, the Malin-Meridian Line, and the Alvey-Meridian line for PacifiCorp to use its scheduling rights available to it. If there is insufficient capacity in the combined capability of the Midpoint-Malin line, the Malin-Meridian Line, or the Alvey-Meridian Line, charges will be applied by Bonneville to PacifiCorp consistent with subsection 5(e)(3) of the AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

5. PAYMENT PROVISIONS

(a) As compensation for the AC Intertie transmission services provided hereunder, PacifiCorp shall pay Bonneville, in accordance with the provisions of Exhibits B and C, and as follows:

(1) PacifiCorp shall pay Transmission Demand charges for North-to-South and for South-to-North service, which shall equal the sum of the products obtained by multiplying the North-to-South and the South-to-North Transmission Demands for each month by the Demand Charge; and

(2) PacifiCorp shall pay for energy transmitted hereunder each month, determined as follows:

(A) For North-to-South service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall be the greater of (1) the product obtained by multiplying the North-to-South Billing Energy for each month by the Energy Charge, or (2) a minimum energy payment, based upon the Energy Charge and an 85 percent load factor. Such minimum energy payment shall be calculated as follows: Transmission Demand (MW) x 8760 hours x Energy Charge (m/kWh) x 0.85 ÷ 12; and

(B) For South-to-North service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall equal the product obtained by multiplying the South-to-North Billing Energy for each month by the Energy Charge.

(C) Such payment shall include charges determined by multiplying the amount of hourly losses, calculated in accordance with the transmission loss factor specified in Exhibit D, by the Energy Charge.

6. TRANSMISSION LOSSES

To compensate Bonneville for Electric Power losses incurred in providing the services hereunder, both for deliveries from PacifiCorp and for deliveries to PacifiCorp, PacifiCorp shall schedule and make available to Bonneville on the corresponding hour 168 hours later or on another hour to be agreed upon by the Parties, and at points to be agreed upon by the Parties, the amounts of Electric Power calculated in accordance with the Loss Factors specified in Exhibit D.

7. POWER SCHEDULING

PacifiCorp shall submit, or arrange to have submitted, to Bonneville by 1400 hours Pacific Time on each Workday:

(a) a separate schedule for North-to-South and South-to-North transfers of Electric Power to be made available to Bonneville for each hour of the following day or days through the next Workday. Such North-to-South and South-to-North schedules may be netted against each other. Changes to such schedules by PacifiCorp shall be accepted up to 30 minutes prior to the hour for which such schedule change is desired;

(b) separate schedules of the hourly amounts of Electric Power to be made available pursuant to section 6 for transmission losses for each hour of the following day or days through the next Workday;

(c) changes to schedules other than those permitted pursuant to subsection 7(a) shall be accepted at any time as mutually agreed by the Parties.

8. REVISION OF EXHIBITS

(a) The initial rate schedules attached as Exhibit B have been confirmed and approved by the FERC on an interim basis. The UFT rate schedule has been approved on a final basis. If the final rate schedules which are approved by the FERC are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated General Transmission Rate Schedule Provisions shall be attached hereto and made a part of this Agreement effective as of the date specified in the FERC's approval.

(b) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) and FERC rules.

(c) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then current AC Intertie and DC Intertie operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, which has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with PacifiCorp. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that any charge specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate incorporating such revised charges. Such new exhibit

shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(e) If the Parties agree to any changes to Exhibit C pursuant to this Agreement Bonneville shall prepare and issue a revised Exhibit C.

9. WAIVER OF BONNEVILLE'S ENERGY SERVICE OBLIGATION

(a) PacifiCorp agrees that the disposition of Electric Energy for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement shall result in a reduction of Bonneville's obligation to PacifiCorp under section 5(b) of the Northwest Power Act. Bonneville's obligation to supply firm power under the Power Sales Contract, as amended or replaced, shall be reduced by the maximum amount of Electric Energy which PacifiCorp is obligated to provide for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement. Bonneville shall implement such reduction as described in subsection (b) below.

(b) To carry out the provisions of subsection (a) above, PacifiCorp shall submit to Bonneville a revised Firm Resources Exhibit and associated data as specified under the Power Sales Contract effective on the effective date of the notice pursuant to subsection (a) above. The Firm Resources Exhibit shall include, as a Firm Resource, the amount of PacifiCorp's obligation to provide Electric Energy for use outside of the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement.

10. COMPLIANCE WITH LONG-TERM INTERTIE ACCESS POLICY

Except as otherwise specified in this Agreement, transmission service provided by Bonneville to PacifiCorp over the AC Intertie shall be subject to the terms of the LTIAP. Notwithstanding the terms of the LTIAP, the Parties agree that no mitigation charges shall be applicable under this Agreement. The Parties also agree that the transmission services being provided hereunder are in accordance with Section 4(b) of the LTIAP (New Transactions not subject to Capacity Limits). The

terms of this Agreement shall not be subject to change upon amendment of the LTIAP, except by mutual agreement of the parties; provided, however, Bonneville may change the Protected Areas Exhibit C to the LTIAP and apply such changes prospectively to resources not licensed at the time of the change without the agreement of PacifiCorp. A resource which has been licensed in the past, and for which a new license is pending, shall be considered licensed.

11. PACIFIC NORTHWEST AC INTERTIE CAPACITY OWNERSHIP EXCHANGE RIGHTS

PacifiCorp shall have the right to exchange all or a portion of its AC Intertie firm transmission contract rights acquired under this Agreement with any party receiving Pacific Northwest AC Intertie Capacity Ownership (Capacity Ownership) rights for up to 125 MW of Capacity Ownership rights, to the extent the Capacity Ownership party has rights to assign all or a portion of its Capacity Ownership allocation. To the extent Bonneville has a first right of refusal to acquire Capacity Ownership rights from a Capacity Ownership party, PacifiCorp's exchange rights under this section 11 shall have priority. Such exchange between PacifiCorp and the Capacity Ownership party shall be approved by Bonneville, which approval shall not unreasonably be withheld, and shall ensure that rights, benefits and obligations

to Bonneville under the affected agreements are preserved.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
ACTING *Assistant Administrator for Power Sales*

Name Sydney D. Berwager
(Print/Type)

Date 5/26/94

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date June 1, 1994

(PMTT-8170-W:PMT\CT\PACAD.DOC)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. *Reducing Charges for Interruptions*. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{/(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Exhibit B

1993

TRANSMISSION RATE SCHEDULES AND

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

Transmission Parameters

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1]

1. North-to-South Transactions:

   a. 01/01/94 to 05/31/94: 75 MW

   b. 06/01/94 and thereafter: 125 MW

2. South-to-North Transactions:

   a. 01/01/94 to 05/31/94: 75 MW x Intertie South-to-North RTC ÷ 4800 MW

   b. 06/01/94 and thereafter: 125 MW x Intertie South-to-North RTC ÷ 4800 MW

[1] Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

Transmission Loss Factors

Transmission Loss Factor to be Applied to Transmission Pursuant to the Southern Intertie Transmission (IS) Rate Schedule

Rate Schedule	Loss Factor
IS-93 B	3.0%

EXECUTIVE SUMMARY

LONG-TERM INTERTIE ACCESS POLICY

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

INTRODUCTION

The Pacific Northwest-Pacific Southwest Intertie began operation in 1968. Congress authorized the construction of the Intertie to provide an additional market for surplus BPA power, thereby providing greater assurance that we would repay the U.S. Treasury for the Federal investments in the Northwest's power system. To the extent there was capacity excess to Federal needs, Congress also intended that the Intertie allow nonfederal utilities in the Northwest and California to take advantage of the diverse load patterns and resource types between the two regions.

The present capability of the Intertie is about 5,200 megawatts (MW), 3,200 MW on the two alternating-current (AC) lines and 2,000 MW on the direct-current (DC) line. Ownership of the Intertie in the Northwest is shared by BPA, Portland General Electric Company (PGE) and Pacific Power & Light Company (PP&L). We provide access to all Northwest generating utilities. Ownership in California is shared by four investor-owned and municipal utilities.

In the early 1980s demand for sales over the Intertie increased dramatically. Nearly every utility in the Northwest had excess power to sell and forecasted a surplus into the next decade and beyond. Northwest utilities frequently filled the Intertie with nonfirm energy and sought to negotiate long-term transactions with California. Prior to 1984 and the implementation of the Interim Intertie Access Policy (IAP), BPA lost significant revenue opportunities by allowing other utilities unfettered access to the Intertie. Combined effects of (1) the Northwest Preference Act, 16 U.S.C. §837, et seq., which gives Northwest utilities a special competitive advantage over us; (2) oversupply conditions in the Northwest; and (3) a restricted market in California due to limited ownership of the Intertie in California caused us to lose sales. We were unable to make our payments to the U.S. Treasury.

In 1984 we implemented the Interim IAP, followed by the Near-Term IAP in 1985. These policies governed access to the Intertie while we developed a Long-Term Intertie Access Policy (LTIAP).

The LTIAP, issued by the Administrator on May 17, 1988, accomplishes the following objectives which have guided us throughout the process:

1. The LTIAP assures BPA of reasonable access to the Intertie to sell both firm and nonfirm energy, thereby enhancing our ability to repay, with interest, $8 billion in Treasury investments.
2. The policy is a reasonable and effective means of safeguarding our $120 million investment in fish and wildlife protection.
3. It balances the competing demands of nonfederal utilities for Intertie access to sell, exchange, or purchase both firm power (through long-term contracts) and nonfirm energy (through the short-term, spot-market).

4. It provides a basis for greater planning certainty to utilities.
5. It allows for efficient use of generating resources in the Northwest and California.
6. It specifically addresses competitive concerns between California and the Northwest.
7. In doing all of the above, it strikes a balance between the Northwest and California, among generating and nongenerating utilities, other BPA customers, environmental interests and Federal taxpayers.

Issuance of this policy culminates our review of comments submitted by over 150 different utilities, regulatory agencies and interest groups. Through a combination of formal, transcribed meetings and informal discussions, we have increased our knowledge of their positions -- and they of ours. We have twice appeared before the U.S. House Subcommittee on Water and Power Resources to answer questions regarding the IAP. Though often cumbersome and lengthy, the process has produced a policy which addresses the demands of all parties.

Balancing interests. We have been put in the difficult position of balancing the competing interests for use of the Intertie. The sum of the demands placed on the Intertie far exceeds the facility's ability to meet them.

Our total-requirements customers insist that BPA should protect its revenues in order to maintain stable power rates and to repay the U.S. Treasury in a timely manner. They suggest that BPA should allocate firm and nonfirm Intertie access to itself first, always assuring that BPA would be able to sell its surplus power. Northwest generating utilities seek a policy which allows sufficient and assured access for their own firm and nonfirm sales. California parties generally argue for a policy which allows them unconstrained access to inexpensive Northwest and Canadian resources. Environmental organizations support a policy that would prevent the Intertie from encouraging development that would harm fish and wildlife resources.

Our main concern in reaching this balanced policy has been reconciling BPA's need to meet its fiscal obligations with these other competing demands for use of the Intertie. While BPA has the discretion to implement the "Federal-first" policy supported by our full requirements customers, the LTIAP instead provides significant access to nonfederal utilities for a variety of transactions while protecting BPA from revenue shortfalls.

It is not reasonable to suggest, as California commenters did in the public process, that BPA incur revenue losses to be recovered through rate increases to its total-requirements customers. These customers have a strong statutory argument -- explained in the decision -- that we should adopt a Federal-first policy to maximize Federal sales over the Intertie. By rejecting Federal-first, we incur an obligation to provide these customers with rate stability through alternative means. First among these alternative protections is the reservation of Intertie capacity for BPA sales.

If the revenue-protective measures adopted in the LTIAP prove unworkable or unduly controversial, the obvious remedy is not more access for nonfederal utilities. Instead, it is Federal-first.

FORMULA ALLOCATION

The Intertie accomodates transactions in two distinct markets. Sellers of power to California sell in two distinct markets, one for long-term transactions and one for short-term sales. Formula Allocation in the LTIAP refers to Intertie capacity made available for short-term sales of energy. We have taken a hard look at Formula Allocations as it has been one of the most hotly debated issues throughout the LTIAP's development.

The LTIAP continues the basic Formula Allocation method used in the Near Term Intertie Access Policy (NTIAP) of allocating access to the Intertie based on three possible conditions. We have changed the specifics of each Condition to reflect criticisms and suggestions made on the two LTIAP drafts. Provisions for Conditions 2 and 3 address directly the contentious anti-competitive concerns between California and the Northwest.

Condition 1. Condition 1 under the NTIAP incorporated the pre-existing Exportable Agreement, which expires on December 31, 1988. Parties to the agreement declare amounts of surplus energy available for export at the applicable BPA rate. If total declarations of exportable energy exceed the available Intertie Capacity or the size of the Pacific Southwest market, whichever is smaller, each party to the agreement is allocated access to the smaller amount based on its share of total declarations.

The 1986 draft LTIAP proposed that upon expiration of the Exportable Agreement a condition of spill or likelihood of spill on the Federal Columbia River Power System (FCRPS) would trigger Condition 1. BPA and Northwest Scheduling Utilities could declare surplus energy available for export and BPA would allocate access to the Intertie based on the ratio of each declaration to the sum of all declarations multiplied by the available Intertie Capacity. Each Scheduling Utility's allocation would be limited by the ratio of its regional hydroelectric capacity to the total regional hydroelectric capacity of the Scheduling Utilities multiplied by the total of all declarations (the "Hydro Cap").

We received comments on the 1986 draft which led us to revise Condition 1 to mirror the Exportable Agreement more closely. Under the 1987 draft a condition of spill or likelihood of spill on the FCRPS determined Condition 1. BPA and Scheduling Utilities could declare surplus energy available for export at the applicable BPA rate and receive a share of available Intertie Capacity based on the Hydro Cap. To the extent that the market for Northwest energy at BPA's price was less than the available Intertie Capacity, we allocated access to the Intertie to equal that market.

Generally, commenters on the 1987 draft did not argue against Condition 1 per se. They focused instead on its specific provisions. The bulk of the comments were directed at the Hydro Cap and at allocating Intertie capacity based on the size of the California market rather than the size of the Intertie capacity. In response to concerns heard at the public meetings in January 1988, we proposed an alternative Condition 1 allocation method. The LTIAP adopts this recent proposal.

The True-Up. The market for power in California is often less than the available Intertie capacity because of minimum generation requirements in California. As the Intertie is expanded and Southwest utilities bring on new generation that cannot be displaced with spot-market purchases, the frequency of this situation is likely to grow.

The 1987 draft allocated Intertie capacity based on the size of the California market as a protection against revenue shortfalls. Analyses indicated that we would lose approximately $16.4 million in 1989 by allocating to the Intertie rather than the market. This loss would decrease to $10.7 million in fiscal year 1992. Beyond 1992 the difference would increase, mainly due to projected fuel price increases.

The heart of the revenue problem is the Northwest Regional Preference Act, 16 U.S.C. 837, et seq., which requires BPA to quote an energy price to Northwest utilities before making any sale to the Southwest. This creates a problem in which Northwest utilities, which are BPA's competitors, know our price -- but we do not know their prices. In Condition 1, where the size of the Southwest market is less than available Intertie Capacity, Northwest utilities are able to use this information to undercut the BPA price and use their allocations to reduce BPA's hourly sales to a small Southwest market. If a "real-time" BPA pricing iteration were even possible, we would still be required to announce our new price to the Northwest. Regional preference makes BPA a "sitting duck" for its competitors.

Allocating according to the California market size would reduce BPA's vulnerability by reducing the size of Scheduling Utility allocations. This provision came under attack, however, from both California and Northwest parties. The alternative discussed at the January 27 public meeting seemed to allay concerns regarding BPA's market control. No one disputes that the Regional Preference Act causes BPA a revenue dilemma, especially at times when we face spill on the hydro system. The true-up alternative is the least intrusive remedy.

The Hydro Cap. Both the 1986 and 1987 LTIAP drafts allocated Intertie capacity based on a utility's hydroelectric capability. The logic for the Hydro Cap was that when the Federal system is spilling or likely to spill, the maximum allocation to utilities with greater hydroelectric resources would increase, thus decreasing the probability of wasting the resources by spilling. Under this provision, BPA's share of allocations would tend to increase due to its large hydroelectric capacity.

Much of the debate over the Hydro Cap focused on two issues. First, removing the Hydro Cap could cause hydro-based utilities to spill. Second, without the Hydro Cap, utilities could "overdeclare" by including uneconomic combustion turbines in their declarations with no intent of ever operating them.

Discussion at the January meetings helped resolve these concerns. When the Federal hydro system faces spill, other systems might not always be in the

same condition. The Hydro Cap could give disproportionately large shares of Intertie Capacity to hydro-based utilities when they may not face a threat of spill, while frustrating the marketing activities of utilities with hydro and thermal resources. Furthermore, several utilities and BPA indicated that if a utility is facing spill with insufficient access to market the available energy on the Intertie, such energy could generally displace Northwest thermal generation.

Several factors would help deter overdeclarations. First, the take-or-pay feature of our IS-87 transmission rate requires a utility to pay for its allocation whether or not it is used. Second, BPA monitors declarations and is aware of each utility's resources and capabilities. We have not observed significant overdeclarations under past policies. Third, from time to time we can request documentation on each utility's declaration as a further insurance against abuse.

Conditions 2 and 3. Allegations of anti-competitive practices on both the northern and southern portions of the Intertie were made during the debate over Formula Allocations. California commenters argue that pro-rata allocations to nonfederal utilities under the LTIAP would tend to stabilize prices at levels higher than those at which sellers might increase their total sales by reducing prices. The Northwest just as logically concludes that pro-rata allocations of California Intertie capacity suppress prices below levels that would prevail in a market where more buyers independently bid for Northwest energy.

We recognized that in implementing a long-term policy we must try to resolve this issue to meet the goals outlined for the LTIAP. We therefore proposed in section 5(d) of the 1987 draft LTIAP to cease pro-rata allocations to non-Federal utilities under Conditions 2 and 3 after completion of the third AC Intertie, provided anti-competitive problems in the Southwest were cured by that time. This proposal was discussed extensively during the public meetings in January 1988 and again in comment letters, mainly from California parties. The final LTIAP takes this proposal a step further. Section 5(d) now ceases pro-rata allocations under Conditions 2 and 3 for an 18-month experimental period.

We will analyze the success or failure of the experiment throughout its term. We will be particularly concerned about the removal of restrictions on California's portion of the Intertie. Utilities, regulators, and other interested parties will be encouraged to express their views in writing and through informal discussions. At least 30 days before the experiment ends, we will issue a written report on whether to continue the experiment.

The experiment will work as follows. Under Condition 2, when the declarations of BPA and Northwest utilities exceed Intertie capacity, we will make a pro-rata allocation to BPA and leave the remaining block of Intertie capacity available to Northwest utilities as a whole. Each Northwest utility could then compete to make sales to Southwest utilities, with no assurance of any individual allocation. Under Condition 3, when the declarations of BPA

and Northwest utilities are less than Intertie capacity, BPA will receive an allocation equal to its declaration and Northwest utilities will receive a block allocation equal to the sum of their declarations. After regional utilities, U.S. extraregional utilities and then Canada have access to remaining Intertie capacity. During Condition 3, we expect significant competition whenever the size of the California market is less than Intertie capacity.

Until the experiment is in effect, Conditions 2 and 3 are similar to those in the NTIAP and the two LTIAP drafts.

The LTIAP retains pro-rata allocations under Condition 1. Allocation under Condition 1 appears to be of less concern to California commenters than allocation during other conditions. Alternative Formula Allocation proposals recognized the importance of pro-rata allocations when the Northwest faces spill conditions. Retention of Condition 1 allocations will (1) help assure nonfederal utilities of Intertie access when hydrological conditions might otherwise force them to spill, and (2) provide an enforcement mechanism for the Protected Area provisions described below.

Some commenters have suggested that we allow access to Canadian utilities equal to that of Northwest utilities. The courts, however, have upheld our policy that capacity excess to our needs must be provided on a fair and nondiscriminatory basis first to Northwest utilities. If the Free Trade Agreement between Canada and the United States now being considered in Congress and the Canadian parliament is implemented, the distinction between U.S. extraregional utilities and Canadian utilities will no longer be made.

ASSURED DELIVERY

Utilities seek firm access to the Intertie for long-term transactions. The LTIAP refers to this kind of access as Assured Delivery. The earlier NTIAP did not provide for Assured Delivery service.

Amount. The final LTIAP reserves 800 MW for Assured Delivery transactions. This is an increase from the 420 MW reserved in the 1986 draft. BPA lost $213 million in fiscal year 1987; we do not want to exacerbate this problem with the final LTIAP. Given these uncertainties, we are cautious about committing major portions of the Intertie for long-term nonfederal use.

Yet, the 800 MW upper limit in itself is a fairly dramatic departure from the past. It will facilitate a greater number and variety of firm transactions than before. Our studies indicate an annual revenue loss of approximately $9 million in lost nonfirm revenue and displaced firm power sales to our public agency customers. The revenue effects on BPA have been quantified further in a study by the PNUCC. These adverse revenue effects, offset by mitigation measures discussed below, have been found acceptable by a fairly broad cross-section of commenters.

In the public meeting and comment letters, most parties seemed satisfied with the 800 MW if we were to consider increasing it upon completion of the third AC project. BPA will reassess the 800 MW limit upon commercial operation or termination of the project.

Exhibit B Allocations. As for the limits on types of transactions, BPA is convinced of the wisdom of imposing limitations on firm power sales. These limits are shown in Exhibit B of the LTIAP. From the standpoints of environmental quality and financial risks, it seems appropriate to limit Assured Delivery capacity to the amount of firm surplus presently available in the Northwest for export sales. In a change from the 1987 draft policy, the LTIAP provides that Scheduling Utilities may use their individual Exhibit B amounts for sales or exchanges.

The final LTIAP does not allocate the remaining 356 MW of Assured Delivery capacity among Scheduling Utilities. That amount will be available for exchange transactions of Scheduling Utilities on a first-come, first-served basis.

We have reached agreement (or agreement in principle) covering 341 MW of Assured Delivery service. Agreements include a 20-year 105 MW firm power sale from Montana Power Company to Los Angeles Department of Water and Power; a 41 MW firm power sale from Tacoma City Light to Western Area Power Administration (WAPA); a 45 MW firm power sale from Longview Fibre/Cowlitz County Public Utility District to WAPA; and a 20-year 150 MW seasonal exchange between The Washington Water Power Company and Pacific Gas and Electric Company. Each of these agreements accommodates our lost revenue concerns differently.

To allow for maximum use of the Intertie, a utility granted Assured Delivery may shape its firm power sale into the months of September through December by delivering up to 1.8 times its Exhibit B amount. During those fall months, spot market energy sales to the Southwest tend to be less than in the spring when the region's hydroelectric dams are more often near or in a spilling condition. If a utility shapes Assured Delivery energy into the fall, less firm energy may be shaped into remaining months of the operating year so that the total energy delivered does not exceed its annual Exhibit B energy maximum for firm sales.

BPA will also continue to work with Nonscheduling Utilities to provide the opportunity to sell the output of their generating resources over BPA's Intertie capacity.

Mitigation. Mitigation refers to conditions imposed on a utility for an Assured Delivery contract. Intertie Capacity not available to BPA because of Assured Delivery contracts executed between a Northwest utility and a Southwest utility can reduce BPA revenues and inhibit BPA's ability to make its Treasury payments. During the operating year BPA often has power available to fully load the Intertie. Assured Delivery granted under these circumstances would reduce BPA's revenues, thereby putting at risk our ability to meet our obligations to the Treasury.

This fiscal concern is in potential conflict with the policy objective underlying the 800 MW of Assured Delivery -- assisting Northwest utilities in disposing of their surpluses by means of long-term firm power sales to the Southwest. Strong objection was received from our Priority Firm Power customers to our absorbing the entire cost (lost revenues) of these transactions and the subsequent passing of the costs to them in increased rates. California and Northwest generating utilities generally tend to agree that some form of mitigation is due BPA. They question the level of compensation and what provisions for mitigation should be included in the LTIAP.

The 1986 draft of the LTIAP allowed Assured Delivery without regard to the adverse impacts on BPA's ability to sell firm power or nonfirm energy. Both the 1987 draft and the LTIAP impose mitigation upon utilities with Assured Delivery contracts. The mitigation provisions in the LTIAP provide only partial compensation for the revenue impacts resulting from transactions, but provide sufficient assurance that these transactions over the Intertie will not harm our revenue recovery.

It would be a false precision to claim that we could develop mitigation measures that offset dollar-for-dollar the losses projected in any 20-year study. Assumptions about annual rainfall, gas prices, aluminum prices, and load growth make this exercise judgmental. With this limitation in mind, the LTIAP incorporates the following mitigation provisions.

One mitigation measure requires that during any hour in which prescheduled energy sales are made under Condition 1 and Condition 2 Formula Allocation

procedures, a utility must deduct its Assured Delivery amount from its Formula Allocation amount. The total amount of Intertie access granted to each utility is equal to its Formula Allocation. If a utility's Assured Delivery amount is greater than its Formula Allocation, then that utility must purchase enough energy from BPA or, during Condition 1, other Northwest utilities to make up the difference. This mitigation measure will partially offset the spot-market revenues BPA will lose by granting Assured Delivery.

Under the other mitigation measure, if BPA has invoked Condition 1 or Condition 2 Formula Allocations, cash out provisions of exchange contracts become inoperative. Cash outs allow a Northwest utility to accept dollar payments from a Southwest utility in lieu of actual energy returns. Prohibiting these during Conditions 1 and 2 has the effect of increasing the north-to-south capability of the Intertie when energy is being returned and increasing the size of the market for BPA and Scheduling Utility sales.

The draft LTIAP required energy returns under seasonal exchanges to the California/Oregon border (COB) or the Nevada/Oregon border (NOB). This was initially included in the mitigation provisions for seasonal exchanges. However, BPA needs the certainty of available capacity resulting from return requirements at COB/NOB. For this reason, the final LTIAP includes this provision as a standard requirement for all exchanges rather than considering it a mitigation measure.

The LTIAP also allows utilities the opportunity to negotiate individual packages of mitigation in addition to the LTIAP's stated mitigation provisions. Such case-by-case mitigation packages could be a combination of the above mitigation provisions or could include beneficial arrangements for BPA that have not been addressed in this policy. Our main concern in any mitigation package is recovery of any spot-market revenue losses, but we will also be looking at the operational impacts of any proposal.

Extraregional Access. Provisions in the 1987 draft for firm transactions by extraregional utilities required that the utility must provide some benefit to BPA, such as increased storage, improved system coordination or operation, or other consideration of value. In addition, the utility must agree to the mitigation provisions of the policy. Canadian utilities were required to wait for access until after the Intertie was rated at 7900 MW.

In reconsidering this provision we saw no reason for denying Canadian utilities access for firm transactions until after the Intertie is upgraded to 7900 MW if Canadian utilities are willing to provide increased coordination or other items of value. This provision of limiting Canadian access to after an upgrade of the Intertie has been deleted from the LTIAP.

As with Formula Allocation, BPA anticipates that if the Free Trade Agreement is passed the distinction between U.S. extraregional utilities and Canadian utilities will no longer exist.

FISH AND WILDLIFE PROTECTION

Protected Areas. The LTIAP prohibits Intertie access for new hydro projects licensed within "protected areas" -- river reaches withdrawn from hydro development due to the presence of wildlife or anadromous and high-value resident fish. BPA also has designated areas where we have determined that investments in habitat, hatchery, passage, or other projects may result in the presence of anadromous fish. The Northwest Power Planning Council (Council) has proposed a protected area program that covers the entire Northwest. BPA's designations, however, cover only the Columbia River basin.

Our focus is on hydro developments which will frustrate our investments made in the region to achieve the goals of the Council's Fish and Wildlife Program. The LTIAP ensures that those expenditures and existing productive habitat will not be harmed by future hydro developments. BPA has designated protected areas by using information collected through the Council's Hydro Assessment Study.

Under the LTIAP, we will consider the Council's final protected area program or any revisions the Council may include in the future. We will also consider appropriate state comprehensive river plans. The policy should effectively eliminate utilities' fears that they never know with certainty whether a hydro resource will qualify, or continue to qualify, for access to the Intertie.

The LTIAP does not necessarily prevent hydro development in protected areas. However, the protected area provisions will send an unambiguous, self-enforcing message to FERC, other regulators, and hydro developers that no Intertie access will be provided for projects constructed in areas of greatest concern to BPA and the Council.

Enforcement. If a Scheduling Utility proceeds to acquire a license or purchase power from a hydro project developed in a protected area, BPA will reduce the amount of that utility's power transmitted over the Intertie during Condition 1. Depending upon the size of the project, the reduction may affect both Assured Delivery and Formula Allocations. These reductions will take place regardless of whether power from the protected area project is actually transmitted on the Intertie. There is no need to trace power flows from a protected area resource.

Projects not affected by the Policy. For all hydro projects not affected by BPA's protected area designations, BPA will intervene in FERC proceedings if we determine that projects -- new or existing, inside or outside the Columbia Basin -- pose significant threats to our fish and wildlife responsibilities.

The provisions do not affect hydro projects licensed before the effective date of the policy. While we recognize a potential for existing projects to harm BPA fish and wildlife investments, we do not believe there is sufficient evidence to indicate that those projects are presently operating contrary to

the Council's Fish and Wildlife Program or that the Council has been unable or unwilling to implement Program measures through the FERC process. Measures affecting existing projects in the Council's Program are explicitly directed to FERC and state agencies for implementation.

We have provided a limited procedure to provide access to the Intertie in the case of a project a developer believes will contribute to the Council's Fish and Wildlife Program and BPA investments. However, our decision to provide access relies on a clear demonstration of the benefits and a regional consensus.

Finally, the LTIAP creates a limited exception for Protected Area projects that an investor-owned utility might be forced to acquire under PURPA. To qualify, however, the affected utility must pursue all legal remedies available to avoid purchasing the Protected Area project output.

LONG-TERM INTERTIE ACCESS POLICY

GOVERNING TRANSACTIONS OVER FEDERALLY OWNED
PORTIONS OF THE
PACIFIC NORTHWEST–PACIFIC SOUTHWEST INTERTIE

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

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FINAL LONG-TERM INTERTIE ACCESS POLICY

Section 1. **Definitions**

1. "Administrator" means the Administrator of Bonneville Power Administration (BPA) and is used interchangeably with BPA.

2. "Administrator's Power Marketing Program" refers to all marketing actions taken and policies developed to fulfill BPA's statutory obligations. These actions and policies are based on exercises of authority to act, consistent with sound business principles, to recover revenue adequate to amortize investments in the Federal Columbia River power and transmission systems, while encouraging diversified use of electric power at the lowest practical rates. In the Northwest, the Administrator's Power Marketing Program covers BPA's obligations to provide an adequate, reliable, economical, efficient, and environmentally acceptable power supply, while preserving public preference to Federal power. In the Southwest, the Administrator's Power Marketing Program covers activities to market surplus Federal power at equitable prices, while preserving regional and public preference to Federal power, and to assist in marketing Northwest nonfederal power.

3. "Allocation" means the share of the Intertie Capacity made available for short-term sales of energy.

4. "Assured Delivery" means firm transmission service provided by BPA under a transmission contract to wheel power covered by a contract between a Scheduling Utility and a Southwest utility. Assured Delivery contracts may not exceed 20 years in duration. The service is interruptible only in the event of an uncontrollable force or a determination made pursuant to sections 7 or 8 of this policy.

5. "Available Intertie Capacity" is defined as the physically available capacity controlled by BPA, reduced by the capacity reserved under Section 2 of this policy, and the capacity necessary to satisfy Assured Delivery contracts not subject to operational mitigation requirements under this policy.

6. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts; and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act.

7. "Exchange" refers to various types of transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power, at prespecified delivery rates, from North to South during the Southwest's peak demands and returns of capacity and/or energy from South to North during other times. Transactions vary depending on the lag between deliveries and returns. A "naked capacity" transaction might require off-peak energy returns within 24 hours, whereas a seasonal exchange might call for firm power returns within 6 months.

8. "Extraregional Utilities" are generating utilities, or divisions thereof, that do not provide retail electric service and do not own or operate significant amounts of generating capacity in the Northwest.

9. "Formula Allocation" means the process by which Intertie Capacity made available for short-term sales of energy.

10. "Intertie" means the two 500-kv alternating current (AC) transmission lines and one 1000 kv direct current (DC) line, which extend from Oregon into California or Nevada, and any additions thereto identified by BPA as Pacific Northwest-Pacific Southwest Intertie facilities.

11. "Intertie Capacity" means the North to South transmission capacity of the Intertie controlled by BPA through ownership or contract; increased by power scheduled South to North, decreased by loop flow, outages, and other factors that reduce transmission capacity; and further decreased by Pacific Power & Light Company's schedules, under its scheduling rights at the Malin substation (BPA Contract Nos. DE-MS79-86BP92299 and DE-MS79-79BP90091).

12. "Mitigation" refers to the requirements imposed by BPA on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's firm power transaction, that inhibit BPA's ability to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless a scheduling utility either agrees to a specially designed charge or negotiates substitute measures with BPA on a case-by-case basis.

13. "Nonscheduling Utility" means a nonfederal Northwest utility that owns a Qualified Northwest Resource, but does not operate a generation control area within the Pacific Northwest. A Nonscheduling Utility requesting Intertie access for its resource must do so through the Scheduling Utility (or BPA) in whose control area the resource is located.

14. "Pacific Northwest" (or "Northwest") is defined in the Northwest Power Act, 16 U.S.C. §839e, as the states of Oregon, Washington, and Idaho; the portion of Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and any contiguous service territories of rural electric cooperatives serving inside and outside the Pacific Northwest, not more than 75 air miles from the areas referred to above, that were served by BPA as of December 1, 1980.

15. "Protected Area" means a stream reach within the Columbia River drainage basin specially protected from hydroelectric development because of the presence of anadromous or high value resident fish, or wildlife. Protected areas may also include stream reaches which could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

16. "Qualified Extraregional Resource" means:

(a) a generating unit located outside the Northwest that was in commercial operation on the effective date of this policy. However, the term excludes portions of units covered as Qualified Northwest Resources.

(b) after BPA has determined that the capacity of the Intertie is rated at approximately 7,900 MW, all resources located outside of the Northwest, other than the portions of extraregional resources covered as Qualified Northwest Resources.

17. "Qualified Northwest Resource" excludes BPA Resources, but includes:

(a) Resources located inside the Northwest that are in commercial operation as of the effective date of this policy.

(b) Scheduling Utility extraregional generating resources dedicated to Northwest loads on the effective date of this policy. This term includes pro rata portions of Montana Power Company's and Pacific Power and Light Company's shares of the Colstrip No. 4 generating station, based on the ratio of their respective regional loads to their respective total loads; and Idaho Power Company's share of Valmy No. 2.

(c) New regional resources of Scheduling Utilities, except for hydroelectric resources located in Protected Areas.

18. "Resource" means an electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

19. "Scheduling Utility" means the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The term excludes Utah Power & Light Company, either as a separately owned company or as a division of another corporation, which has sufficient transmission capacity to the Southwest without access to the Federal Intertie.

20. "Seasonal Exchange" means a transaction that takes advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power, at a prespecified delivery rate, from North to South during the Southwest's summer load season and from South to North during the Northwest's winter load season. Seasonal Exchanges may involve payments of additional consideration to reflect the relative seasonal values of power throughout the western United States. Seasonal Exchange schedules of Northwest utilities will be referred to as "deliveries," and schedules of Southwest utilities will be referenced as "returns." A Scheduling Utility must be able to support its summertime firm power deliveries with generating resources that are surplus to its Northwest requirements. The sum of a Scheduling Utility's energy resources for each month in which deliveries are made (with special concern for August) must exceed its corresponding Northwest loads by an amount sufficient to support the Seasonal Exchange.

21. "Section 9(i)(3) resource" means a Scheduling Utility resource that BPA has granted priority in receiving BPA transmission, storage and load factoring services as defined in §9(i)(3) of the Northwest Power Act.

Section 2. **Intertie Capacity Reserved for BPA**

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) transmit all of BPA's surplus firm power and to serve other obligations,

(b) perform obligations, including, but not limited to, the existing transmission contracts listed in Exhibit A, to the extent such obligations differ from the conditions specified in this policy,

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit B to this policy, and

(d) satisfy BPA firm obligations, that have not been prescheduled, by using unutilized portions of Formula Allocation amounts.

Section 3. **Conditions For Intertie Access**

(a) All Intertie access will be granted pursuant to the conditions and procedures of this policy, unless otherwise specified in the three existing BPA transmission contracts listed in Exhibit A.

(b) BPA will provide Intertie access only for BPA Resources and the Qualified Northwest Resources of Scheduling Utilities, except to the extent that Qualified Extraregional Resources are permitted access under this policy.

(c) BPA will provide Assured Delivery and allocate remaining Intertie Capacity when providing such access will not substantially interfere with operating limitations of the Federal system. Examples of these limitations, which reflect BPA's obligation to operate in an economical and reliable manner consistent with prudent utility practices, include:

(1) The BPA Reliability Criteria and Standards,
(2) Western Systems Coordinating Council minimum operating reliability criteria,
(3) North American Electric Reliability Council Operating Committee minimum criteria for operating reliability, and
(4) coordination agreements among BPA, scheduling utilities and other Federal agencies regarding resource and river operations.

(d) Any utility that has contractual or ownership rights to Pacific Northwest-Pacific Southwest Intertie capacity or to other transmission lines to California or the Southwest market must fully utilize such capacity prior to receiving any access to BPA's Intertie Capacity. If a Scheduling Utility with Intertie rights needs BPA Intertie Capacity to reach a particular Southwest utility, BPA will consider negotiated swaps of capacity to accommodate such requests.

Section 4. **Assured Delivery for Intertie Access**

Subject to the limitations and other conditions in this section and in other sections of this policy, BPA has determined that it can provide limited Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) **General Provisions**

(1) **Existing Transmission Contracts.** BPA will provide Assured Delivery for the remaining terms of the firm power sale and Seasonal Exchange contracts identified in Exhibit A to this policy.

(2) **Utilities Owning Or Controlling Southwest Interconnections.** Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. Except for transactions covered by section 4(b) of this policy, a utility with capacity on an intertie, through contract or ownership, must utilize all such capacity on a firm basis before receiving any Assured Delivery.

(3) **Nature Of Transactions.** BPA will not provide Assured Delivery for transactions which a Scheduling Utility cannot demonstrate to be other than an advance arrangement to sell nonfirm energy.

(4) **Waiver Of BPA Service Obligation.**

(A) **Hydroelectric Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest hydroelectric energy shall provide, under 16 U.S.C. §837b(d), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided .

(B) **Thermal Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest thermal energy shall provide, under 16 U.S.C. §839f(c), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided. Such reduction shall become effective at the time BPA determines that it has reached energy load/resource balance, or at a date as specified in the Assured Delivery contract.

(5) **Exchange Contracts.** Exchange contracts must specify that all return energy be scheduled to either the AC Intertie point of interconnection at the California-Oregon border ("COB") or the DC Intertie point of interconnection at the Nevada-Oregon border ("NOB"). Exchange contracts must also specify prescheduled determinations of hourly energy returns.

(6) **Satisfying Requests For Assured Delivery.** All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made.

(b) **New Transactions Not Subject To Capacity Limits**

(1) **Joint Ventures.** Joint ventures between BPA and utilities, such as firm displacement contracts, which allow BPA to increase its sales of surplus power qualify for Assured Delivery.

(2) **Sales In Lieu Of Exchanges.** BPA may offer to satisfy Scheduling Utility demands for Seasonal Exchanges by selling them incremental amounts of surplus firm power during winter months. Upon committing to purchase such incremental firm power at negotiated prices that reflect BPA's

lost opportunities for summer sales, a Scheduling Utility will qualify for Assured Delivery (with mitigation) to wheel an equal amount of firm capacity and energy over the Intertie during summer months.

(3) **Conditions**. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(b)(1) and 4(b)(2). Relevant contracts must be presented for review when Assured Delivery is requested. BPA will satisfy a request within 60 days after a Scheduling Utility has demonstrated satisfaction of the requirements of this policy.

(c) **Transactions Subject To Capacity Limits Under This Policy**

(1) **Maximum Amounts Of Assured Delivery**. BPA will provide 800 MW of Assured Delivery for firm power sales and Exchanges identified in this policy. BPA will reassess the amount of Assured Delivery capacity when the 3d AC Intertie project is either completed or abandoned. Moreover, the 800 MW amount may be subject to some reduction if the DC Terminal Expansion project is not completed on schedule.

(2) **Exhibit B amounts**.

(A) **Current maximum**. Each Scheduling Utility's maximum Assured Delivery amount for firm sales equals its average firm energy surplus, shown in Exhibit B to this policy. BPA will reserve capacity equal to each Scheduling Utility's Exhibit B allocation subject to section 4(c)(2)(D) below. Except for Montana Power Company (MPC), Tacoma City Light, and Cowlitz County Public Utility District, Exhibit B represents projected Scheduling Utility surpluses for the 1988-89 operating year. In satisfaction of all obligations to MPC under Northwest Power Act section 9(1)(3), MPC's Exhibit B amount is set at 105 MW to facilitate long-term sales of firm power from its share of the Colstrip No. 4 coal-fired generating station. Exhibit B amounts for Tacoma and Cowlitz are increased to accommodate existing firm power transactions.

(B) **Shaping**. Firm power sales eligible for Assured Delivery may be shaped within the following ranges. During the months of September through December, a Scheduling Utility may deliver firm energy at a rate up to 1.8 times its Exhibit B average firm surplus amount. During the months of January through August, a Scheduling Utility may deliver firm energy at a rate no greater than 1.0 times its Exhibit B amount. However, total delivered energy may not exceed the Exhibit B annual firm energy maximum.

(C) **Other uses of Exhibit B amounts**. BPA will not entertain Assured Delivery requests for firm power sales in excess of a utility's Exhibit B maximum. However, a Scheduling Utility may use any portion of its Exhibit B maximum, not used for firm power sales, for exchange transactions supported by Qualified Northwest Resources.

(D) **Future changes**. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount will be revoked if, upon revision, a utility's individual Exhibit B amount has declined or if a utility has sold firm power to another utility seeking to increase its Exhibit B

average firm surplus amount. A Scheduling Utility may increase its individual Exhibit B amount by purchasing surplus firm power from BPA or any Scheduling Utility with an Exhibit B amount.

(3) **Other Capacity**. The remaining capacity available for Assured Delivery under this policy is offered to Scheduling Utilities, on a first-come, first-served basis, for Exchange transactions supported by Qualified Northwest Resources. When section 4(c)(2)(D) of this policy is implemented to reduce the Exhibit B maximum of any Scheduling Utility, the reduction will be added to the capacity made available under this provision. Any utility with an Exhibit B amount must exhaust such capacity before requesting Assured Delivery under this provision.

(d) **Mitigation**

(1)**Operational Mitigation**

(A) **Southbound deliveries**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures to preschedule energy deliveries, each utility's Assured Delivery amount shall be deducted from its formula allocation to determine its share of energy scheduled on the Intertie. If the remainder is negative for a given utility, then that utility must make up the difference by purchasing sufficient energy as follows:

(i) during Condition 1 from BPA or any Scheduling Utility with a Formula Allocation during that hour;

(ii) during Condition 2 from BPA, however, if BPA is not in the market the utility may purchase sufficient energy from any other utility.

(B) **Northbound returns**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures, a utility may utilize the cash-out provisions of an Exchange contract only by reducing one-for-one the amount of North-to-South Intertie capacity otherwise available to it under this policy. The rate of cash out during any condition shall not exceed the rate at which the exchange return could have been scheduled.

(2) **Negotiated mitigation**. A Scheduling Utility may also elect to negotiate with BPA on a case-by-case basis a package of mitigation measures involving mutually agreeable consideration of value commensurate with the service provided.

Section 5. **Formula Allocation Methods**

(a) **Limits On Intertie Capacity Available For Formula Allocation**. Generally, BPA will determine Intertie Capacity available for Formula Allocations after first taking into account the amount of Intertie Capacity necessary to satisfy requirements of the Administrator's Power Marketing Program, existing transmission contracts listed in Exhibit A, and Assured Delivery contracts executed by BPA pursuant to this policy. However, in determining Available Intertie Capacity during Condition 1, BPA will not consider the Assured Delivery contracts to the extent they are subject to operational mitigation requirements. BPA may reduce any allocation, if additional Intertie Capacity is required to minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.

(b) **Protected Area Decrements**. Except as provided in section 4(d)(2)(A) of this policy, BPA will reduce each Scheduling Utility's allocation by any Protected Area decrement imposed pursuant to section 7(d).

(c) **Allocation Methods**.

(1) **Condition 1**

(A) **Until December 31, 1988**. Intertie Capacity will be allocated pursuant to the Exportable Agreement (BPA Contract No. 14-03-73155), when applicable.

(B) **After December 31, 1988**. Condition 1 will be in effect when the Federal hydro system is in spill or there is a likelihood of spill, as determined by BPA. Available Intertie capacity will be allocated pursuant to the following procedure:

(i) Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective declarations to total declarations, multiplied by the Available Intertie Capacity.

(ii) During Condition 1, whenever BPA is unable to utilize its full pro rata share of intertie usage BPA will take larger allocations on ensuing days until the difference in pro rata intertie usage is eliminated.

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, Formula Allocations for BPA and each Scheduling Utility will approximate, by hour, the ratio of each declaration to the sum of all declarations, multiplied by the available Intertie capacity.

(B) If BPA sales drop below 75 percent of its allocation during Condition 2, BPA may take larger allocations on ensuing days until the difference is eliminated.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA and Scheduling Utilities' allocations will equal their declarations. The remaining Intertie capacity will be made available first to U.S. Extraregional Utilities and then to other Extraregional Utilities. Section 3(d) of this policy shall not apply to Scheduling Utilities during Condition 3.

(d) **Formula Allocation Experiment**. BPA is interested in exploring the proposal that it cease making individual Formula Allocations to Scheduling Utilities under Conditions 2 and 3. However, BPA must work with Northwest and Southwest utilities to develop the information capability to accommodate a new scheduling system for nonfederal access. As soon as this can be accomplished BPA will substitute the following provisions for section 5(c) on an 18-month experimental basis:

(1) **Condition 1**

Same as section 5(c)(1).

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, the Formula Allocation for BPA will approximate, by hour, the ratio of BPA's declaration to the sum of all declarations, multiplied by the Available Intertie Capacity. The remaining capacity will be made available as a block to Scheduling Utilities. Section 5(c)(2)(B) of this policy shall apply.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA's allocation will equal its declaration. The remaining Intertie capacity will be made available, first, as a block to satisfy the declarations of Scheduling Utilities, second, to U.S. Extraregional Utilities, and third to other Extraregional Utilities. Section 3(d) of this policy shall not apply during Condition 3.

(e) **Data Collection and Evaluation.** Commencing when this policy goes into effect and continuing during the course of the experiment described in section 5(d), BPA will collect information on the following topics relevant to future allocation procedures:

(1) effect on BPA revenue of allocating to nonfederal utilities as a group rather than individually.

(2) impairment of Intertie access for California utilities presently lacking ownership in the southern portion of the Intertie,

(3) any loss of sales to BPA due to a failure to share unused capacity among California entities with ownership or contractual interests in the Intertie,

(4) effects of the experiment on small Scheduling Utilities.

During the course of the experiment, interested parties may submit written comments and recommendations on these issues.

(f) **Findings and conclusions.** At least 30 days before the end of the experiment described in section 5(d), BPA shall publish a report of its findings on the experiment and its decision on whether section 5(d), with possible modification, should be continued as the permanent method of Formula Allocation.

Section 6. **Access for Qualified Extraregional Resources**

(a) **Assured Delivery.** Any request for Assured Delivery of power from a Qualified Extraregional Resource would be granted only by contract which, in addition to the Mitigation measures specified in section 4(d), must include

benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether they would cause substantial interference with the Administrator's Power Marketing Program. An environmental review would also be conducted.

(b) **Formula Allocation**. Under Condition 3, energy from Qualified Extraregional Resources has access to the Intertie. In addition, BPA may provide Extraregional Utilities with Formula Allocation under other conditions, if the utility agrees by contract either to increased participation in the Pacific Northwest's coordinated planning and operation, or to provide other consideration of value, apart from the standard BPA wheeling rate, commensurate with the services provided.

Section 7. **Fish and Wildlife Protection**

(a) **Purpose**. New hydroelectric projects constructed in Protected Areas may substantially decrease the effectiveness of, or substantially increase the need for, expenditures and other actions by BPA, under Northwest Power Act section 4(h), to protect, mitigate or enhance fish and wildlife resources. Intertie access will not be provided to facilitate the transmission of power generated by any new hydroelectric projects located in Protected Areas and licensed after the effective date of this policy. This provision does not apply to added capacity at existing projects.

(b) **Effect**. This section imposes automatic operational limitations on a utility by reducing the amount of energy that can be scheduled over the Intertie, thereby increasing costs or reducing revenues for any utility owning or acquiring the output of a Protected Area hydroelectric resource.

(c) **Implementation**. Protected Area designations for stream reaches in the Columbia River Basin are shown in Exhibit C to this policy. Exhibit C uses Environmental Protection Agency stream reach codes. Subject to review and possible modification, BPA will consider the adoption of comprehensive state watershed management plans and a comprehensive protected area program developed by the Pacific Northwest Electric Power and Conservation Planning Council subsequent to implementation of this policy. BPA will also consider revisions to Protected Area designations if the Council's Program is amended.

(d) **Enforcement**. If a Scheduling Utility or Nonscheduling Utility owns, or acquires the output from, a hydroelectric project covered under the restrictions of section 7(a), BPA will reduce that utility's Formula Allocation by either the nameplate rating of the project (in the case of ownership), or the amount of capacity acquired by contract.

(e) **Exceptions**.

(1) **PURPA Projects**. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an investor-owned utility has been compelled to acquire the output of a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act (PURPA). To qualify for this exception, the investor-owned utility must demonstrate:

(A) that it has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the Protected Area resource in question;

(B) that it has petitioned its state regulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources in recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy;

(C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and

(D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that it was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

(2) **Projects Contributing to Council's Fish and Wildlife Program or BPA Investments**. Access will be automatically denied for projects developed in protected areas unless BPA receives sufficient demonstration that a particular project will provide benefits to existing or planned BPA fish and wildlife investments or the Council's Program. BPA's determination will be based on:

(A) information provided by the project developer, Federal and state fish and wildlife agencies, and tribes; or

(B) action by the Pacific Northwest Power Planning Council.

Section 8. **Other Enforcement Provisions**

(a) Whenever the terms of this policy are not being met, BPA will inform the appropriate utility of the nature of the noncompliance and actions that may be taken to achieve compliance. If noncompliance is not corrected within a reasonable period, BPA may deny access for a resource and refuse to accept schedules.

(b) Upon approval of the proposed U.S.-Canada Free Trade Agreement by the Canadian Parliament and the United States Congress, any and all distinctions made in this policy between Canadian and United States Extraregional Utilities shall terminate on the effective date of the Agreement.

EXHIBIT A
EXISTING AGREEMENTS FOR INTERTIE CAPACITY

This is a list of existing BPA transmission contracts that were signed before the implementation of the NTIAP and will continue to receive Intertie access under the LTIAP.

Utility	BPA Contract No.	Expiration Date
Washington Water Power Company	DE-MS79-81BP90185	07/01/91
Washington Water Power Company	14-03-791101	09/01/88
Western Area Power Administration	DE-MS79-84BP91627	10/31/90

EXHIBIT B
INTERTIE CAPACITY AVAILABLE FOR ASSURED DELIVERY

BPA has reserved 800 MW of Intertie capacity to be available for nonfederal firm transactions. This capacity is allocated as follows:

A. Average Firm Surplus Allocations:

UTILITY	AVERAGE MW FIRM SURPLUS	
Chelan County PUD #1	10	
Cowlitz County PUD #1	45	1/
Douglas County PUD #1	0	2/
Eugene Water and Electric Board	14	
Grant County PUD #1	26	
Seattle City Light	23	
Snohomish County PUD #1	0	
Tacoma City Light	41	3/
Idaho Power Company	87	
Montana Power Company	105	4/
Puget Sound Power and Light	0	
Washington Water Power	93	
	444	

NOTE: The Average Firm Surplus (AFS) is directly from the PNUCC Northwest Regional Forecast of March 1987 for the period 1988-89 except as noted below. It includes resources operational on the effective date of this policy. Export contracts are included as loads. Utilities may use their AFS allocations for long term firm sales or for exchanges. Portland General Electric Company and Pacific Power & Light Company are not eligible for an AFS allocation because of their existing interconnections with the Southwest.

1/ Cowlitz Co. PUD's AFS is the amount of their existing export of the Longview Fibre resource. Longview Fibre is considered to be a Federal resource in the Northwest Regional Forecast and is not included under Cowlitz.

2/ Douglas County PUD's AFS is 2; but Douglas has previously requested to show zero.

3/ The amount displayed for Tacoma is the amount of their existing exports displayed in the Northwest Regional Forecast.

4/ Montana Power Company's AFS was increased from 80 MW to 105 MW in settlement of obligations under Northwest Power Act section 9(i)(3).

B. Intertie Capacity Available for Exchanges: The above allocations for sales of firm surplus may be used for exchanges. The remaining 356 MW of capacity is available on a first come-first serve basis for exchanges only under the terms of the LTIAP. If there is a decrease in a utility's firm surplus and the utility does not have a contract for that amount, BPA will allocate the difference to capacity available for exchanges by revising this Exhibit B.

EXHIBIT C
PROTECTED AREAS

Exhibit C corresponds to the Northwest Power Planning Council protected area designations within the Columbia Basin, as specified in the Columbia River Basin Fish and Wildlife Program. Stream reaches designated as protected areas are identified by Environmental Protection Agency stream reach codes. Information about designations are contained on hard copy computer printouts or computer diskette copies which are available to the public upon request.

This revision reduces the Transmission Demand from 125 MW to 93 MW on lines C.1.b. and C.2.b. due to implementation of the Capacity Ownership Agreement, Contract No. DE-MS79-95BP94628.

TRANSMISSION PARAMETERS

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1/]

1. North-to-South Transactions:

a.	01/01/94 to 05/31/94:	75 MW
b.	06/01/94 to 12/31/94:	125 MW
c.	01/01/95 and thereafter:	93 MW

2. South-to-North Transactions:

a.	01/01/94 to 05/31/94:	75 MW x Intertie South-to-North RTC ÷ 4800 MW
b.	06/01/94 to 12/31/94:	125 MW x Intertie South-to-North RTC ÷ 4800 MW
c.	01/01/95 and thereafter:	93 MW x Intertie South-to-North RTC ÷ 4800 MW

1/ Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Account Executive

Name Patrick G. McRae
(Print/Type)

Date January 11, 1995

PACIFICORP

By _____

Name Jerry D. Miller
(Print/Type)

Title Manager, Power System Services

Date January 23, 1995

(PMLAN-MPSM-W:\PMT\CT\94285c_1.DOC)

Contract No. DE-MS79-94BP94332

AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

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This AC INTERTIE AGREEMENT ("Agreement"), executed June 1, 1994, by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

W I T N E S S E T H:

WHEREAS the Parties have entered into the Transmission Agreement (Contract No. DE-MS79-79BP90091), as amended, which

hereinafter is referred to as "Midpoint-Medford Agreement"; and

WHEREAS the Parties have entered into the Intertie Agreement (Contract No. DE-MS79-86BP92299), as amended, which hereinafter is referred to as "Intertie Agreement"; and

WHEREAS the Parties have entered into an Agreement of Principles, dated May 28, 1993, which hereinafter is referred to as "Letter of Understanding" and which provides, among other things, for the revision of certain terms and conditions in the Midpoint-Medford Agreement and the Intertie Agreement; and

WHEREAS the Parties have entered into the Midpoint-Meridian Transmission Agreement (Contract No.DE-MS79-94BP94333) which hereinafter is referred to as "Midpoint-Meridian Transmission Agreement" which replaces and supersedes the Midpoint-Medford Agreement; and

WHEREAS the Parties desire to replace and supersede the Intertie Agreement with this Agreement; and

WHEREAS the Parties have entered into the AC Intertie Operation and Maintenance Agreement (Contract No. DE-MS79-93BP94278) which hereinafter is referred to as "AC Intertie O&M Agreement"; and

WHEREAS Bonneville and PacifiCorp are Parties to Contract No. 14-03-59840 ("Malin Substation Construction Agreement") which provides for rights and obligations regarding construction, operation, ownership and use of the Malin Substation and desire to continue such agreement for the term of this Agreement; and

WHEREAS PacifiCorp has constructed a 500 kV line from the interconnection with Bonneville at Alvey Substation to Meridian Substation ("Alvey-Meridian Line") to provide increased Load Carrying Capability; and

WHEREAS Bonneville has expanded the Rated Transfer Capability of the AC Intertie to approximately 4800 megawatts and has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line; and

WHEREAS PacifiCorp and Bonneville have acquired joint ownership in the Alvey-Meridian Line and related facilities as provided for in Amendatory Agreement No. 2 to the Intertie Agreement ("Payment Agreement"), Amendatory Agreement No. 1 to the Intertie Agreement ("Option Agreement") attached hereto as Exhibits A and D respectively and Exhibit B hereto; and

WHEREAS nothing in this Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Agreement;

NOW, THEREFORE, in the interest of resolving issues of AC Intertie rights and service to PacifiCorp's Load Area, now and in the future, Bonneville and PacifiCorp are entering into this Agreement to accomplish the following goals:

(a) To enable Bonneville's planning, construction, operation and maintenance of an AC Intertie with a bidirectional Rated Transfer Capability of approximately 4800 megawatts and to enable PacifiCorp's planning, construction, operation and maintenance of facilities to serve its Load Area.

(b) To permit the Parties' specified use of the Buckley-Alvey Loop in a manner that does not jeopardize reliable service on either Party's system.

(c) To limit PacifiCorp's right to use its own facilities to schedule power and energy from its Load Area to adjoining areas and to ensure that this right is exercised in a manner that does not reduce the Operational Transfer Capability of the AC Intertie.

(d) To facilitate joint development of facilities by Bonneville and PacifiCorp as specified in this Agreement.

(e) As between the Parties, to facilitate the economical development and fair allocation of any AC Intertie transfer capability above 4800 megawatts.

It is the intention of the Parties that this Agreement be implemented and interpreted to best effectuate the above stated goals. Where this Agreement makes reference to not unreasonably withholding consent or agreement, the reasonableness of each Party's position will be judged with reference to the above stated goals.

1. Term of Agreement. This Agreement shall be effective and shall supersede the Intertie Agreement in accordance with section 15 herein when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate when all of the facilities comprising the AC Intertie are permanently taken out of service. Upon termination of this Agreement, all liabilities

accrued hereunder shall be and are hereby preserved until satisfied.

2. Exhibits. Exhibits A through E are incorporated as part of this Agreement. Revisions to the Exhibits shall be by mutual consent.

3. Plan-of-Service for AC Intertie.

(a) Bonneville's Right to Establish Plan-of-Service. PacifiCorp agrees that Bonneville alone shall have the right to establish any Plan-of-Service for upgrading the AC Intertie to approximately 4800 megawatts, provided such Plan-of-Service is in keeping with Prudent Utility Practice, and further provided such Plan-of-Service does not result in reducing PacifiCorp's Load Carrying Capability.

(b) PacifiCorp's Right to Comment. Bonneville shall provide PacifiCorp the opportunity to comment on any such Plan-of-Service Bonneville may establish.

4. AC Intertie Construction and Ownership up to Approximately 4800 Megawatts of Rated Transfer Capability

(a) Alvey-Meridian Line Rights. To achieve the upgrade of the AC Intertie to a Rated Transfer Capability of approximately 4800 megawatts, Bonneville has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line which is jointly owned by Bonneville and PacifiCorp as provided for in the Payment Agreement and Exhibit B. For the term of this Agreement, Bonneville shall have the unrestricted right to use such ownership interest. Bonneville

may use such unrestricted right for purposes including, but not limited to, the interregional transfer of electric power, the integration of the electric power output of generation resources, and for service to the electric power loads of Bonneville's customers. Bonneville and PacifiCorp have shared, in accordance with the percentages specified in Exhibit B, the actual costs of facilities associated with construction of the Alvey-Meridian Line and other related additions. Unless otherwise stated in Exhibit B or in the AC Intertie O&M Agreement, Bonneville shall pay 42 percent and PacifiCorp shall pay 58 percent of the operation and maintenance costs of those facilities specified in Exhibit B. PacifiCorp shall bear all operation and maintenance costs for those facilities used exclusively to serve PacifiCorp's own loads. PacifiCorp and Bonneville shall act in good faith and use best efforts, including utilization of all reasonable legal remedies, to obtain and protect all necessary permits and licenses for the Alvey-Meridian Line.

(b) Captain Jack Substation. Bonneville has constructed and, except for those facilities which PacifiCorp owns pursuant to section 4(b)(3) herein, owns the Captain Jack Substation and the associated interconnection to COTP. Bonneville's ownership includes the land on which the substation and the interconnection are located. Bonneville has connected the Captain Jack Substation to PacifiCorp's 500 kV system between Meridian Substation and Malin Substation where the COTP

interconnects with the AC Intertie subject to the following terms, conditions and exceptions:

(1) Bonneville has constructed and owns terminal equipment, lines, and facilities required to interconnect the COTP with the Captain Jack Substation.

(2) Bonneville has constructed and owns the series and shunt compensation equipment and facilities located in the Captain Jack Substation required to connect to the COTP.

(3) PacifiCorp and Bonneville have shared equally in the cost of the bay 3 terminal equipment and facilities, which PacifiCorp owns, including the land on which such facilities are located, required to loop PacifiCorp's Malin-Meridian 500 kV line ("Malin-Meridian Line") into the Captain Jack Substation.

(4) PacifiCorp, at its expense and subject to Prudent Utility Practice, may install transformation equipment at the Captain Jack Substation. PacifiCorp agrees to provide Bonneville the one-line diagram and plot plan for the installation of transformation equipment in a timely fashion for inclusion in Bonneville's Plan-of-Service. Subsequent changes in the one-line diagram or plot plan of transformation equipment are subject to mutual consent.

(c) Modification of Facilities.

(1) Except in regard to the Malin Substation,

PacifiCorp agrees that it will make or permit Bonneville to make, at Bonneville's expense, any improvements or modifications of PacifiCorp's facilities in the Buckley-Alvey Loop that are required to accomplish Bonneville's Plan-of-Service. Unless otherwise mutually agreed, Bonneville shall own such improvements or modifications unless they cannot be removed without impairment or damage to PacifiCorp's facilities, in which case such modifications or improvements shall be jointly owned by Bonneville and PacifiCorp.

(2) AC Intertie Reactive Support. After joint studies have been completed and the Parties have mutually agreed that additional reactive support is required at the Malin Substation or Captain Jack Substation to support the AC Intertie, PacifiCorp shall be financially responsible for its share of the cost of such added reactive support.

(3) At such time as the Parties mutually agree, which agreement shall not be unreasonably withheld, that a second 500/230 kV transformer is required at the Malin Substation or a 500/230 kV transformer is required at the Captain Jack Substation, the Parties shall jointly develop the plan of service for such transformer(s). Each Party shall have the right to acquire up to a one-half ownership interest in such transformer(s) at a pro-rata share of cost, provided that PacifiCorp's Load Carrying Capability is not impacted. If a Party does not participate in the

ownership of such transformer(s) at the Malin or Captain Jack Substations at the time such transformer(s) are installed, such Party shall have the unilateral right to acquire up to a one-half ownership interest based on a pro-rata share of the original cost plus capital additions, if any, at a future date to the extent that capacity is available.

(4) Except as provided for in subsection 4(c)(1) herein, any improvements or modifications of the Buckley-Alvey Loop shall be by mutual consent, which consent shall not be unreasonably withheld. Except as provided for in subsections 4(c)(2) and 4(c)(3) above, installation of any equipment in the Malin Substation shall be made pursuant to the terms of the Malin Substation Construction Agreement.

(5) If Bonneville determines additions or modifications to the Alvey-Meridian Line are necessary to maintain the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie at 4800 megawatts, Bonneville may, by written notice, cause PacifiCorp to add such equipment or make such modifications, and Bonneville and PacifiCorp shall share equally in the costs and ownership of such additions and modifications unless otherwise mutually agreed. PacifiCorp and Bonneville shall share equally in any Incremental Capacity resulting from such modifications.

5. Rights of Use.

(a) Determination of AC Intertie Rated Transfer Capability and Operational Transfer Capability. PacifiCorp agrees that Bonneville may determine the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie, provided such determination is in keeping with Prudent Utility Practice, and further provided it does not have the effect of reducing PacifiCorp's ability to serve up to its Load Carrying Capability as specified in this section 5.

(b) Bonneville's Right to Use of PacifiCorp's Malin-Meridian Line. PacifiCorp shall provide Bonneville, at no charge, sufficient capacity in the Malin-Meridian Line for Bonneville's AC Intertie transactions for itself or on behalf of other parties to enable Bonneville to operate the AC Intertie at its Rated Transfer Capability. To the extent modifications in the Malin-Meridian Line are required to effectuate this subsection 5(b), the cost of such modifications shall be borne equally by Bonneville and PacifiCorp. PacifiCorp shall operate and maintain the Malin-Meridian Line to maintain the Rated Transfer Capability on the AC Intertie in keeping with Prudent Utility Practice.

(c) Bonneville's Rights and Obligations for Intertie Service. PacifiCorp agrees that Bonneville has the right to operate the AC Intertie up to its Rated Transfer Capability or Operational Transfer Capability, subject to the following terms and conditions:

(1) Subject to section 4(c)(2) herein, Bonneville shall provide reactive support to maintain the Rated Transfer Capability of the AC Intertie.

(2) Bonneville shall provide transmission reinforcement to maintain the Rated Transfer Capability of the AC Intertie.

(3) Bonneville shall not rate or operate the AC Intertie in a manner that interferes with PacifiCorp's use of its Load Carrying Capability as described in subsections 5(d)(1), 5(d)(2), and 5(d)(3) below. However, Bonneville may make use of PacifiCorp's unused Load Carrying Capability for AC Intertie transactions for itself or on behalf of other parties at no additional charge, except as otherwise provided in this Agreement.

(d) PacifiCorp's Rights and Obligations for Service to Load.

(1) Upon energization of the Alvey-Meridian Line, PacifiCorp shall have the right to serve PacifiCorp's Load Area and parallel paths, pursuant to section 10 herein, up to the Load Carrying Capability specified as follows:

(A) PacifiCorp shall have a Load Carrying Capability of 1875 megawatts.

(B) By the date when PacifiCorp's Load is expected to exceed the Load Carrying Capability recognized in subsection 5(d)(1)(A) herein, PacifiCorp shall provide additional facilities to supply power to its Load Area.

(2) The Load Carrying Capability specified in this subsection 5(d) may be correspondingly increased if new transmission facilities are constructed or if modifications are made to transmission facilities that increase the Load Carrying Capability. The effect of any such additions or modifications of transmission facilities on Load Carrying Capability shall be established by mutual agreement of the Parties using the results of joint planning studies conducted pursuant to subsection 5(d)(3) herein, and such mutual agreement shall not be unreasonably withheld.

(3) PacifiCorp's Load in its Load Area, and the date that such load is expected to exceed the Load Carrying Capability, shall be mutually determined by joint planning studies conducted annually, or as otherwise mutually agreed, by PacifiCorp and Bonneville in accordance with normal utility planning criteria. Such studies shall be based on mutually agreed to load forecasts for PacifiCorp's Load, as well as records of actual metered power flows on the then existing transmission lines serving the Load Area. PacifiCorp and Bonneville shall furnish any data reasonably required for the joint planning study.

(4) PacifiCorp shall provide reactive support and internal transmission reinforcement for PacifiCorp's Load, including, but not limited to, 500/230 kV transformation, and 230 kV and below transmission reinforcement. To the extent PacifiCorp fails to provide such reinforcements,

Bonneville shall not be obligated to reduce the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie.

(5) Use of the Summer Lake Substation as a point of delivery by the Parties shall not impact PacifiCorp's Load Carrying Capability or Bonneville's usage of the AC Intertie.

(e) PacifiCorp's Scheduling Rights for AC Intertie Rated Transfer Capability in Excess of 4000 Megawatts. PacifiCorp's Southbound Scheduling Rights are 400 megawatts. PacifiCorp's Northbound Scheduling Rights shall equal 400 megawatts multiplied by a fraction whose numerator is the northbound Rated Transfer Capability of the AC Intertie and whose denominator is the southbound Rated Transfer Capability of the AC Intertie. PacifiCorp shall have the right to net its total northbound and southbound schedules under this Agreement. PacifiCorp agrees to cooperate with Bonneville in its efforts, if any, to secure a northbound AC Intertie Rated Transfer Capability of 4800 megawatts. PacifiCorp's Northbound Scheduling Rights and Southbound Scheduling Rights shall be subject to the following terms and conditions:

(1) To the extent PacifiCorp has unused Scheduling Rights available in any hour under this Agreement, such unused Scheduling Rights shall be available to Bonneville for AC Intertie transactions at no charge.

(2) Except as mutually agreed to, any net southbound

schedules by PacifiCorp in excess of Southbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the southbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie from John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Except as mutually agreed to, any net northbound schedules by PacifiCorp in excess of Northbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the northbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Such excess schedules shall be subject to Bonneville's then effective Long-Term Intertie Access Policy, PacifiCorp's rights under other agreements, and the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. In the event that PacifiCorp's net northbound/southbound schedules exceed PacifiCorp's scheduling rights as described above,

Bonneville shall provide transmission services to PacifiCorp pursuant to the same policies and rates that are generally applicable to Bonneville's other regional utility customers.

(3) If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin 500 kV line ("Midpoint-Malin Line"), the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to use its net Southbound Scheduling Rights available to it, any increment above the combined capability of such facilities shall be deemed to be transmitted from the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Net Northbound Scheduling Rights shall be deemed to be delivered to PacifiCorp at Malin Substation or Captain Jack Substation. If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin Line, the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to integrate deliveries associated with its net Northbound Scheduling Rights available to it, any increment in excess of PacifiCorp's Load that can be served using the combined capability of PacifiCorp's facilities still in service shall be deemed to be transmitted from the Malin Substation to the John Day Substation, or any other AC Intertie

delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Transmission service over the Federal Transmission System shall carry charges and losses as specified in the Midpoint-Meridian Transmission Agreement.

(4) During times when the southbound AC Intertie Operational Transfer Capability is less then the southbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net southbound scheduling rights at Malin Substation and Captain Jack Substation as described herein shall be an amount determined by multiplying the southbound Operational Transfer Capability of the AC Intertie by the ratio of 400 megawatts to the southbound Rated Transfer Capability of the AC Intertie. During times when the northbound AC Intertie Operational Transfer Capability is less then the northbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net northbound scheduling rights shall be an amount determined by multiplying the northbound Operational Transfer Capability of the AC Intertie by the ratio of the Northbound Scheduling Rights to the northbound Rated Transfer Capability of the AC Intertie.

(f) Additional PacifiCorp Wheeling Rights. Until December 31, 2023, during Off-Peak Hours when PacifiCorp's northbound scheduling capability is less than 582 megawatts, Bonneville will provide PacifiCorp the right to utilize Bonneville's unused

northbound capability on the AC Intertie and the DC Intertie at the IS-A Rate, or its successor rate, so as to provide PacifiCorp with a total northbound scheduling capability of 582 megawatts. For the purposes of this subsection 5(f), PacifiCorp's northbound scheduling capability for any hour shall equal the sum during such hour of its Northbound Scheduling Rights hereunder and its northbound scheduling rights under the AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285, including rights under Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Bonneville's unused AC Intertie capability and DC Intertie capability shall be deemed to be capability not required to satisfy Bonneville's firm contractual commitments, as determined by Bonneville. PacifiCorp shall use best efforts to provide Bonneville advance notice of its desire to utilize its rights pursuant to this subsection 5(f). To the extent possible, such notice shall be provided at the time that PacifiCorp submits its preschedules to Bonneville pursuant to section 7 herein, provided, however, that PacifiCorp's failure to provide such notice with preschedules shall not diminish in any way, PacifiCorp's rights under this subsection 5(f).

(g) Remedial Action Schemes. PacifiCorp shall be responsible for providing or assuring, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie either

northbound or southbound. In support of its obligations to provide generator dropping for its net southbound AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on line at the time of a remedial action scheme requirement. Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net southbound AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on line at the time of a remedial action scheme requirement at no cost. To the extent PacifiCorp does not have the capability on line to provide generator dropping from its Mid-Columbia rights for its net southbound AC Intertie schedules, Bonneville shall, to the extent it has available on line generation, provide generator dropping capability to PacifiCorp at no cost. In the event that PacifiCorp no longer has rights to Mid-Columbia generation, PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and the Operational Transfer Capability of the AC Intertie either northbound or southbound shall not be diminished. In support of PacifiCorp's net northbound AC Intertie schedules or its northbound DC Intertie schedules, PacifiCorp shall be responsible for making arrangements for any load dropping requirements. To the extent possible, as determined by Bonneville, Bonneville shall offer to sell remedial action scheme service to PacifiCorp to enable

PacifiCorp to meet its obligations pursuant to this subsection 5(g).

(h) PacifiCorp shall provide Bonneville firm capacity in the existing 500/230 kV transformer at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, provided such capacity will be made available to Bonneville only after PacifiCorp has determined that it has the capacity necessary to meet its own requirements and provided further, that Bonneville's right to use the existing Malin transformer shall be limited to 200 megawatts.

6. Upgrades of the AC Intertie Above Planned Rated Transfer Capability of 4800 Megawatts. After Bonneville has determined that the southbound or northbound AC Intertie Rated Transfer Capability is at least 4800 megawatts, but not more than 4900 megawatts, Bonneville and PacifiCorp agree that if any additions or changes to the Buckley-Alvey Loop or other jointly-owned facilities are required to increase the Rated Transfer Capability of the AC Intertie, such additions or changes shall be by mutual consent of the Parties hereto, which consent shall not be unreasonably withheld. Bonneville and PacifiCorp shall have the right, but not the obligation, to participate equally in such increase in the AC Intertie Rated Transfer Capability resulting from such additions or changes, and, if they do so, each shall share equally in the costs of such additions or changes to the Buckley-Alvey Loop or other jointly owned facilities required for such increases.

7. Scheduling.

(a) Bonneville and PacifiCorp shall schedule through the Joint Intertie Scheduling Office all schedules with southwest entities at the Malin and Captain Jack Substations.

(b) Upon Bonneville's request, PacifiCorp shall notify the Joint Intertie Scheduling Office each recognized workday of the planned schedules over PacifiCorp's parallel facilities, as described and limited in section 10 herein, for the following day or days. PacifiCorp shall also provide Bonneville's schedulers with all preschedule modifications prior to the hour of such schedules in accordance with Bonneville's standard scheduling practices.

8. Losses. The Parties shall be compensated for electric power losses pursuant to Calculation of Losses as shown in Exhibit E. Such compensation shall be based upon an equitable allocation of the Parties' control area losses associated with this Agreement and with the Midpoint-Meridian Transmission Agreement (Contract No. DE-MS79-94BP94333). The loss allocation specified in Exhibit E shall be reviewed at least every five years, but a review may be requested by either Party annually. The loss allocation shall be reviewed by the Parties to reflect any changes to the loss allocation.

9. Waivers. Except as specified in this Agreement and the Letter of Understanding, PacifiCorp waives any claim to any ownership share or right to use the AC Intertie Rated Transfer Capability or to additional scheduling rights based on its

ownership in: (1) existing facilities as such facilities may be modified or (2) the Alvey-Meridian Line.

10. Construction and Operation of Parallel Facilities.

(a) PacifiCorp's right to construct and right to operate existing and new interconnections with Pacific Gas & Electric Company or other utilities adjoining PacifiCorp's service territory in southern Oregon and northern California in parallel with the AC Intertie shall be subject to the following terms and conditions:

(1) The interconnection shall operate at 230 kV or below and shall include a phase shifter, unless the Parties mutually agree that a phase shifter is not required.

(2) On any given hour the sum of PacifiCorp's Load and the schedule on the parallel path shall not exceed the Load Carrying Capability.

(3) Except as provided in subsection 10(c) herein, PacifiCorp's total Rated Transfer Capability on such interconnections shall not exceed 400 megawatts. The total Rated Transfer Capability on such interconnections shall include the 100 megawatt Cottonwood Interconnection with Pacific Gas and Electric Company. The Operational Transfer Capability on such interconnections shall never exceed the Rated Transfer Capability on such interconnections.

(4) PacifiCorp shall schedule as provided in subsection 7(b) herein. In no case shall such schedules exceed the Operational Transfer Capability of such

interconnections.

(5) PacifiCorp shall make available to Bonneville telemetry of the actual power flow over PacifiCorp's parallel path interconnections.

(6) Construction or operation of such interconnections shall not reduce or adversely impact the Operational Transfer Capability of the AC Intertie. If Bonneville determines the operation of any such interconnection reduces or impacts the Operational Transfer Capability of the AC Intertie on any hour, and AC Intertie users have need of additional Operational Transfer Capability on the AC Intertie, upon Bonneville's request PacifiCorp shall reduce schedules to the extent needed to eliminate such impact. PacifiCorp shall not be required to reduce schedules on the parallel paths if the Operational Transfer Capability of the AC Intertie is reduced as a result of outages on the AC Intertie.

(b) Except as provided in subsection 10(c) herein, PacifiCorp shall not construct, participate in, or allow new interconnections for any 345 kV or above transmission lines or facilities from any point on PacifiCorp's system in Oregon to the existing two Malin-Round Mountain-Table Mountain 500 kV lines or the COTP north of Table Mountain.

(c) Notwithstanding the provisions of subsections 10(a)(3) and 10(b) herein, PacifiCorp may (i) construct and operate existing and new interconnections, as referenced in subsection

10(a)(3) herein with Rated Transfer Capability in excess of 400 megawatts, and/or (ii) construct, participate in, and allow new interconnections as referenced in subsection 10(b) herein, if:

(1) such increase in Rated Transfer Capability or new interconnection is needed for PacifiCorp to meet good faith third-party requests for transmission service; and

(2) Bonneville has declined to provide, or lacks transmission facilities to provide, the requested transmission service; and

(3) such actions do not reduce the Rated Transfer Capability of the AC Intertie.

11. Wheeling From Palo Verde. For a period coincident with the term of PacifiCorp's March 23, 1993 Transmission Service Agreement ("TSA") with Southern California Edison Company ("SCE"), PacifiCorp, on hours that PacifiCorp does not require all or a portion of its transmission capacity rights pursuant to the TSA, shall offer Bonneville a first right of refusal to utilize such excess transmission rights under the TSA. PacifiCorp shall have sole discretion to determine whether it is making use of its TSA transmission rights. If Bonneville exercises its right to use PacifiCorp's TSA transmission rights, Bonneville shall reimburse PacifiCorp for SCE's charges to PacifiCorp for such usage. Such reimbursement shall be based upon PacifiCorp's then-effective transmission demand charges from SCE under the TSA which shall initially be $4.00 per megawatt-hour. If Bonneville exercises its first right of

refusal to utilize PacifiCorp's excess TSA transmission rights, Bonneville shall use its own AC Intertie or DC Intertie scheduling capability to accept and transmit power and energy scheduled under this section 11. Additionally, the exercise of such access by Bonneville shall not preclude PacifiCorp from utilizing its transmission rights acquired from Bonneville on the AC Intertie or the DC Intertie.

12. Summer Storage and Spring Energy Option

(a) Summer Storage. For a period of 20 years commencing with the effective date of this Agreement, PacifiCorp shall accept and store energy for Bonneville during the months of June and July of each year, provided that PacifiCorp is not required to reduce generation from its thermal plants to accept such energy. Bonneville shall provide PacifiCorp notice as to the amount of energy Bonneville desires to have stored one-week prior to the beginning of each month that Bonneville will deliver energy to be stored by PacifiCorp. Energy to be stored pursuant to this subsection 12(a) shall be delivered to PacifiCorp at the points of delivery specified in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (Contract No. DE-MS79-92BP93757), as amended or superseded, or such other points as may be mutually agreed to. PacifiCorp may, but shall not be required to, accept more than 100,000 megawatt-hours per month for storage and Bonneville shall deliver no less than 25,000 megawatt-hours per month for storage. Bonneville shall deliver energy to PacifiCorp for storage prior to entering into

the market to sell surplus energy. Unless otherwise mutually agreed, the hourly rate of delivery shall be determined by dividing the total energy to be stored in the month by the number of hours in such month. Except in times of system emergency, Bonneville shall adhere to the agreed-upon schedule of deliveries. PacifiCorp shall return stored energy to Bonneville during the months of September, October and November of each year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June and July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville.

(b) Spring Energy Option. For a period of 20 years following the effective date of this Agreement, if requested by Bonneville, PacifiCorp shall deliver to Bonneville during Off-

Peak Hours, at the Hot Springs Substation, or other mutually-agreed points of delivery, up to 50,000 megawatt-hours during the month of March of each such year. The maximum rate of delivery for such energy shall be 200 megawatts per hour. To exercise its option to take such energy, Bonneville shall notify PacifiCorp by February 15 of each year as to the amount of energy Bonneville desires to have delivered during the following March. Except in times of system emergency, PacifiCorp shall deliver such energy in accordance with Bonneville's request, subject to the limitations of this subsection 12(b). Bonneville shall return the energy delivered by PacifiCorp during the following June 1 through July 15 period during Off-Peak hours at an hourly rate of delivery determined by dividing the amount of energy delivered by PacifiCorp during the previous March by the number of Off-Peak Hours in the June 1 through July 15 period or such other hourly rate of delivery as mutually agreed to. Such March Energy shall be returned to PacifiCorp at points of delivery as specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points of delivery as are mutually agreed.

13. Sale or Assignment.

(a) This Agreement shall inure to the benefit of, and shall be binding upon, the respective successors and assigns of the Parties to this Agreement.

(b) PacifiCorp and Bonneville agree not to sell, assign, lease, sublease, or otherwise transfer this Agreement or any

interest therein, without the written consent of the other Party, such consent not to be unreasonably withheld. PacifiCorp and Bonneville also agree not to sell, assign, lease, sublease, or otherwise transfer any direct or indirect interest in the Malin Substation, the portion of the Midpoint-Malin Line between Summer Lake Substation and Malin Substation ("Summer Lake-Malin Line"), the Malin-Meridian Line, or the Alvey-Meridian Line, without the written consent of the other Party, such consent not to be unreasonably withheld, provided, however, that PacifiCorp's interest in such facilities may be conveyed to its respective trustees as security under a mortgage or deed of trust to secure indebtedness without such written consent, provided that each such trustee may act with respect to such interest only to the extent and in the manner that such act would have been authorized under this Agreement.

(c) If Bonneville or PacifiCorp is acquired in total by other entities, subsection 13(b) shall not apply to such acquisition.

14. Extension of Existing Agreements. The Parties agree that the termination dates of the Midpoint-Meridian Transmission Agreement, the Malin Substation Construction Agreement and all agreements related to joint ownership or interconnection on the Buckley-Alvey Loop, including but not limited to arrangements for the operation and maintenance of new facilities, shall be coincident with the termination date of this Agreement. The Payment Agreement and the Option Agreement are attached hereto

as Exhibits A and D respectively and made a part of this Agreement. The Payment Agreement and the Option Agreement provide for, among other things, certain construction, payment, ownership, operation and maintenance activities in progress at the time of execution of this Agreement. As these activities are completed or superseded by future agreements, PacifiCorp and Bonneville may agree to terminate some or all of the Payment Agreement and the Option Agreement provisions. To the extent any provisions of the Payment Agreement or the Option Agreement are in conflict with this Agreement, the terms and conditions of this Agreement shall prevail.

15. Termination of Agreement. The Parties agree that this AC Intertie Agreement supersedes and terminates in its entirety the Intertie Agreement, Contract No. DE-MS79-86BP92299, provided, however, that any liabilities incurred thereunder are hereby preserved until satisfied.

16. Execution of Other Agreements. The Parties agree to negotiate in good faith and execute construction agreements, operation and maintenance agreements, transmission agreements, and other such agreements that may be required to implement the provisions of this Agreement.

17. Arbitration. In the event of any dispute related to rights or obligations of the Parties, or satisfaction thereof, under this Agreement, including but not limited to the amount or reasonableness of costs, identification of exclusive use facilities, extent of amortization of past costs, and the

reasonableness of withholding consent, either Party may elect to submit such dispute to nonbinding arbitration. If one Party so elects, such Party shall notify the other Party in writing and both Parties shall participate pursuant to the following:

(a) If the Parties cannot agree on an arbiter within 30 days of such notification, the notifying Party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the Parties' written positions. The Party electing the arbitration shall first state its position in a letter to the arbiter. The second Party shall then state its position in a letter to the arbiter. The first Party may then submit a response to the Second Party's position and the second Party may thereafter submit a reply to the first Party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the Parties otherwise mutually agree. The Parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other Party.

(d) The arbiter shall provide the Parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The Parties shall equally share the fee and other costs of the arbiter.

In the event neither Party submits the dispute to nonbinding arbitration or if either Party elects not to accept the finding of the arbiter, the Parties may elect other approaches, including litigation, to resolve the dispute.

18. Rules of Law.

(a) The Parties agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) The construction and interpretation of this Agreement shall be governed solely by Federal law.

(c) This Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither Party shall be under the control of or shall be the agent of or have a right or power to bind the other Party without the other Party's express written consent, except as provided in this Agreement.

19. Delay of Performance. The time for each act specified in this Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the Party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

20. Regulatory Jurisdiction. The provisions of this Agreement are subject to such regulatory agencies having

jurisdiction thereof. Nothing contained herein shall be construed as affecting in any way the right of PacifiCorp to make application unilaterally to the Federal Energy Regulatory Commission for a change in rates, charges, classification, or service, or any rule or regulation, or contract relating thereto, under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.

21. Severability and Breach.

(a) It is the intention of the Parties that the provisions of this Agreement be severable in the event that any of such provisions, or portions thereof, are held to be illegal, invalid or unenforceable by a court of competent jurisdiction; provided that if section 10 herein, or any portion thereof, is found to be illegal, invalid or unenforceable by a court of competent jurisdiction, Bonneville shall have firm transmission rights to 50 percent of the total Rated Transfer Capability of any parallel interconnections other than the 100 megawatt Cottonwood Interconnection between PacifiCorp and Pacific Gas & Electric or other utilities adjoining PacifiCorp's territory in southern Oregon and northern California. In any legal proceeding, Bonneville and PacifiCorp shall act in good faith to defend the enforceability of all provisions of this Agreement.

(b) The Parties agree that breach of this Agreement, or any of its provisions, will cause irreparable harm and that the appropriate remedy is injunctive relief.

22. Definitions.

(a) AC Intertie. For the purposes of this Agreement, the AC Intertie means Bonneville's rights in the alternating current ("AC") transmission facilities for transferring power and energy between Oregon and California as follows: two 500 kV lines extending from John Day Substation to Malin Substation and to the California-Oregon Border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Dixonville and Dixonville-Meridian 500 kV transmission lines; portions of the Alvey, Dixonville, Meridian and Captain Jack Substations; the 500 kV transmission line extending from Captain Jack Substation to the California-Oregon Border; and any modifications, improvements, or additions to such facilities.

(b) Alvey-Meridian Line. The 500 kV transmission line facilities and substations constructed by PacifiCorp that extend from the interconnection with Bonneville's system at Alvey Substation to PacifiCorp's Meridian Substation.

(c) Buckley-Alvey Loop. The 500 kV transmission lines, facilities, and substations from Buckley Substation south to Summer Lake Substation, continuing south to Malin Substation,

west to Meridian Substation, including the Captain Jack Substation, and the Alvey-Meridian Line.

(d) Captain Jack Substation. The substation where COTP interconnects with the AC Intertie in the Pacific Northwest.

(e) California Intertie. The two existing 500 kV AC lines extending northward from within California at Round Mountain Substation and terminating at Malin Substation.

(f) COTP. The 500 kV California-Oregon Transmission Project, which operates in parallel with the California Intertie and terminates at the California-Oregon Border.

(g) DC Intertie. For the purposes of this Agreement, the DC Intertie means Bonneville's rights in the existing 1,000 kV direct current ("DC") transmission line, and associated substation facilities, extending from the Bonneville's Big Eddy Substation to the Nevada-Oregon Border.

(h) Federal Transmission System. The transmission facilities owned by Bonneville.

(i) Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Agreements entered into by Bonneville and regional utilities providing for those utilities' ownership of AC Intertie capacity available as a result of increasing the Rated Transfer Capability of the AC Intertie to 4800 megawatts.

(j) Incremental Capacity. For the purpose of this Agreement, Incremental Capacity means capacity realized through the construction of the Alvey-Meridian Line in excess of the capacity on the previously existing 230 kV Alvey-Meridian line

that was removed as a result of construction of the Alvey-Meridian Line.

(k) IS-A Rate. The Nonfirm Transmission Rate specified in Section II.A. of Bonneville's Southern Intertie Transmission Schedule IS-93, or its successor.

(l) Joint Intertie Scheduling Office. The group of schedulers presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, appointed by Bonneville, Portland General Electric Company and PacifiCorp and designated to coordinate the schedule of energy over the AC Intertie and the DC Intertie.

(m) Load Area. The geographic area encompassing portions of southern Oregon and northern California which is generally south of Eugene, Oregon and Bonneville's Summer Lake Substation and west of Burns, Oregon. Such geographic area shall be limited to:

(1) That area in which PacifiCorp is authorized to provide retail electric service, now and in the future; and

(2) That area in which PacifiCorp provides wholesale electric service at the date of execution of this Agreement; provided that such areas are normally within PacifiCorp's load control area, connected to PacifiCorp's transmission system, and served by the transmission lines in Exhibit C.

Revisions to the Load Area shall be by mutual agreement of the Parties, and such agreement shall not be unreasonably withheld.

(n) Load Carrying Capability. The capability of PacifiCorp's transmission system, as specified in Exhibit C, serving the Load Area and parallel paths as limited by section 10 herein to provide firm transmission service in accordance with Prudent Utility Practice.

(o) Northbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a northerly direction from the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Agreement.

(p) Off-Peak Hours. The first six and last two hours of each day Monday through Saturday and all day Sunday or other hours as mutually agreed to.

(q) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, operational limitations imposed by California utilities, line or equipment outages, stability limits or loop flow.

(r) PacifiCorp's Load. PacifiCorp's net firm load obligations within the Load Area excluding Bonneville's Surprise Valley Electric Cooperative Load transferred by PacifiCorp pursuant to the General Transfer Agreement, Contract No. DE-MS79-82BP90049.

(s) Plan-of-Service. The project plans that Bonneville develops to realize an increase of the AC Intertie Rated Transfer Capability up to approximately 4800 megawatts, which

shall include but are not necessarily limited to plans, schedules, costs, and facility and equipment requirements.

(t) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry prior thereto or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(u) Rated Transfer Capability. The ability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(v) Southbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a southerly direction to the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Agreement.

Amendatory Agreement No. 2 to
Contract No. DE-MS79-86BP92299
03/09/93

AMENDATORY AGREEMENT NO. 2

TO THE INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

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This AMENDATORY AGREEMENT NO. 2 to the Intertie Agreement, Contract No. DE-MS79-86BP92299, executed March 16, 1993, by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PACIFICORP with its principal office in Portland, Oregon (hereinafter collectively referred to as "Parties" and individually as "Party").

W I T N E S S E T H :

WHEREAS the Parties hereto desire to make progress payments towards the design and construction of those facilities identified in Exhibit C to the Intertie Agreement, as amended; and

WHEREAS the Parties have entered into an Interim Payment Agreement, Contract No. DE-MS79-92BP93772 (Interim Payment Agreement), as amended, which provides for partial payment by Bonneville to PacifiCorp in the net amount of $10,000,000 for each Party's costs through May 31, 1992, related to the Alvey-Meridian Line and the AC Intertie (such payment represents a $16,000,000 payment to PacifiCorp and a $6,000,000 payment to Bonneville); and

WHEREAS the Parties have entered into a Cooperative Communication Agreement, Contract No. DE-MS79-92BP93740 (Communications Agreement), which

provides for, among other things, construction of microwave communication facilities needed for the AC Intertie (Intertie Communication Facilities); and

WHEREAS the Parties have entered into a Remedial Action Scheme Agreement, Contract No. DE-MS79-92BP93039, which provides for, among other things, cost-sharing and payment by the Parties for the remedial action scheme equipment needed to support the rated transfer capability of the AC Intertie; and

WHEREAS the Parties have entered into the Sycan Interconnection Agreement, Contract No. DE-MS79-92BP93644 (Sycan Interconnection Agreement), which provides for, among other things, the installation and connection of series capacitors and related equipment (Sycan Addition) to PacifiCorp's Summer Lake-Malin 500 kV transmission line at the Sycan Compensation Station and Summer Lake and Malin Substations; and

NOW, THEREFORE, to establish the Parties' payment obligations throughout the construction phase of the Alvey-Meridian Line; the Alvey, Dixonville, Meridian, and Captain Jack 500 kV Substations; the Sycan Addition; and the Parties' Intertie Communication Facilities; and for continued obligations related to the AC Intertie, the Parties agree to the following:

1. Term of Amendment. This Amendatory Agreement No. 2 shall be effective on the date of execution (Amendment Effective Date) and shall remain in effect concurrently with the Intertie Agreement. All liabilities incurred hereunder shall be preserved until satisfied. Section 1 of the Intertie Agreement is hereby amended to include "Prior to the termination date of this Agreement, and no later than December 31, 2009, the Parties will commence negotiations for a follow-on agreement concerning services associated with the AC Intertie unless this Agreement is extended past 2016 then the Parties will commence negotiation of a follow-on agreement 7 years prior to termination."

2. Termination of Prior Agreement. The Interim Payment Agreement is hereby terminated upon the Amendment Effective Date. All obligations and liabilities incurred thereunder have been satisfied.

3. Definitions.

(a) Section 19(o) of the Intertie Agreement is hereby amended to read:

"(o) Captain Jack Substation. The Substation where the COTP interconnects with the AC Intertie in the Pacific Northwest and is sometimes referred to as the Southern Oregon Substation."

(b) Section 19 of the Intertie Agreement is hereby amended to add the following definitions:

"(p) Actual Costs are Bonneville and PacifiCorp Direct Costs, Indirect Costs, Overhead Costs, AFUDC, Interest and Credits as defined herein which are recorded monthly to construction work in progress (CWIP), retirement work in progress, removal work in progress, or electric plant in service according to generally accepted accounting principles and Prudent Utility Practice allocable to the Alvey-Meridian Line and other related facilities identified in Exhibit C herein. Costs related to construction that would not be capitalized, such as relocation, switching, and conductor transfer shall also be included in Actual Costs. The sharing of AFUDC on CWIP and Interest on electric plant in service is dependent on the timing of payments from the other Party relative to when costs are incurred. Bonneville's normal allocation of Bonneville Overheads and Bonneville Indirect Costs shall be included in the Actual Costs. PacifiCorp's normal allocation of PacifiCorp Overheads shall be included in the Actual Costs.

"(q) Advances are the monthly amounts of projected cash flow estimates for the Cost Shared Facilities expected to be incurred as Actual Costs in a given month as specified in Exhibits G and H.

"(r) Allowance for Funds Used During Construction (AFUDC) shall be as defined in the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts found in 18 CFR, Part 101, Electric Plant Instructions 3.A [17]. AFUDC shall be an Actual Cost until the Party constructing the Cost Shared Facilities is funded by the other Party. AFUDC shall be included in CWIP.

"(s) Bonneville Direct Costs are costs which are readily identifiable or obviously traceable to a specific program, project, or other cost objective and will not be included in Bonneville's Overhead or Indirect Costs.

"(t) Bonneville Indirect Costs are any costs incurred for common objectives which cannot be directly charged to any single point of cost application. Indirect costs are often allocated to various categories of work in proportion to the benefit to each category and will not be included in Bonneville's Direct or Overhead Costs.

"(u) Bonneville Overhead Costs. Bonneville's Overhead Costs are subject to change as Bonneville's methodology for computing Overhead Costs may change and shall be reflected in the Actual Costs. Bonneville's Overhead Costs include the following and will not be included in Bonneville's Direct or Indirect Costs:

"(1) Costs that are distributed each month to benefiting programs using an annual direction of effort basis which may include automated data processing, materials and procurement, tools and work equipment, fixed wing aircraft, helicopter, General Services Administration (GSA) rent and building management, general and administrative, laboratory, and Electric Power Research Institute;

"(2) Costs that are charged to benefiting projects and programs based upon a fixed rate for services performed which include vehicle maintenance, general shops, and equipment use;

"(3) Costs that are loaded to labor charged to specific projects or programs which include personnel benefits and leave accrual; and

"(4) Costs that benefit all construction projects and are charged to all projects as construction overhead.

"(v) Cost Shared Facilities are those facilities identified in the cost share percentage column of Exhibit C herein. Such facilities shall include but are not limited to costs for land, environmental impact studies, preconstruction materials, and construction which PacifiCorp and Bonneville agree to pay through an exchange of payments in accordance with the cost share percentages as provided in Exhibit C.

"(w) Credits are the applicable portion of any income, rebate, allowance, or other receivable relating to any Cost Shared Facilities received by either Party. This includes, but is not limited to, materials, surplus property, scrap, timber revenues and future sales of Jointly-Owned and cost-shared land (Fee-Owned and Easement Rights). Proceeds from Credits shall be paid to the other Party either as a billing credit or by cash refund based on the original Cost Shared Facility proration between Bonneville and PacifiCorp.

"(x) Hazardous Substances mean any hazardous, toxic, or dangerous substance, waste, or material that is now or becomes regulated under any federal, state or local statute, ordinance, rule, regulation or other law now or hereafter in effect pertaining to environmental protection, contamination, or cleanup, including without limitation, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), 42 U.S.C.

9601 et seq., the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq., the Federal Water Pollution Control Act (CWA), 33 U.S.C. 1251 et seq., the Clean Air Act (CAA), 42 U.S.C. 7401 et seq., the Toxic Substances Control Act (TSCA), 15 U.S.C. 2601 et seq. and all comparable programs under Oregon Law.

"(y) Historic Contamination means all contamination through seepage, spill, disposal, or release by any other method, of a Hazardous Substance at or from any facility which occurred prior to the Amendment Effective Date.

"(z) Interest based on AFUDC rates and applicable to electric plant in service, shall be applied to Cost Shared Facilities placed in service before cost reimbursement has occurred.

"(aa) Jointly-Owned refers to those facilities identified in Exhibit C which are not solely owned by either Party.

"(bb) PacifiCorp Direct Costs are costs which are readily identifiable or obviously traceable to a specific program, project, or other cost objective and will not be included in PacifiCorp's Overhead Costs.

"(cc) PacifiCorp Overhead Costs are costs incurred which cannot be directly charged to any single point of application. PacifiCorp Overhead Costs are assigned to various categories in proportion to the benefit of each category. PacifiCorp overhead transactions are made by either allocations or by clearing. PacifiCorp's Overhead Costs are subject to change as PacifiCorp's methodology for computing Overhead Costs may change and shall be reflected in Actual Costs. PacifiCorp Overhead Costs include the following components and will not be included in PacifiCorp's Direct Costs:

"(1) Labor Loading. These costs are directly associated personnel costs and include payroll taxes, leave, and benefits.

"(2) Material Overheads (for stores issues and for direct purchases) includes the costs of purchase, storage, handling and distribution of materials and supplies.

"(3) Tool Overheads represent the costs incurred to the purchase, use, and maintenance of small tools for force account work.

"(4) Transportation Overheads represent the costs incurred to purchase, lease, rent, operate, and maintain the fleet of PacifiCorp vehicles.

"(5) Construction (General) Overheads are all other construction costs incurred as a corporation, but which are not assignable to a specific project. Construction Overheads are applied to PacifiCorp's Direct Costs plus PacifiCorp's Overhead Costs described above in Sections cc(1) through cc(4).

"(dd) Prior Costs. Actual Costs for Cost Shared Facilities incurred by the Parties through December 31, 1991, which are identified in section 7(b) to this Amendment.

"(ee) Project Diagram. Exhibit F to this Amendment describes the plan-of-service for the Eugene-Medford (Alvey-Meridian) project."

4. Revision of Exhibits. Section 2 of the Intertie Agreement is hereby deleted in its entirety and replaced with the following:

"2. Exhibits. Exhibits A through K are hereby incorporated as part of the Intertie Agreement as amended. Revisions to the Exhibits, except for Exhibit K shall be by mutual consent."

The monthly Operation and Maintenance (O&M) charge in Exhibit K may be revised unilaterally by Bonneville once every year to be effective on July 1, but not until after January 1, 1994.

5. Accounting and Record Keeping.

(a) Record Keeping. Each Party shall keep up-to-date books and records of financial transactions, and other arrangements in carrying out the terms of this Amendatory Agreement No. 2. Such books and records shall be kept in accordance with the system of accounts prescribed for electric utilities by FERC and shall be available for inspection on a regular basis to the other Party. Each Party shall have access to such records of the other Party as required for audit, for state and local tax preparation purposes, for regulatory purposes, and as necessary for engineering, design, and project management review.

(b) Continuing Property Records. Each Party shall maintain the complete cost records and investment reports on facilities they constructed in accordance with the Project Diagram, as well as investment records which delineate the ownership percentage in facilities constructed by the other Party.

For example, Bonneville will record 100 percent of the facilities constructed by Bonneville with an offsetting credit for PacifiCorp's percentage of ownership of those facilities and record Bonneville's ownership percentage of facilities constructed by PacifiCorp.

In conjunction with the final accounting and true-up of project costs, Bonneville and PacifiCorp shall exchange investment records and appropriate support documentation normally required for FERC account investment analysis. This may include, but is not limited to, structure/hardware lists, plan and profile drawings, and bills of materials. Bonneville and PacifiCorp shall provide periodic exchanges of information as necessary to properly identify

replacements, retirements, additions and improvements as such activities occur on the Jointly-Owned facilities.

(c) Capital Spare Parts. Capital spare parts for the Jointly-Owned facilities are subject to joint-ownership and cost-sharing if they are unique to a specific Jointly-Owned or Cost Shared Facility and if they are stored at or near the Cost Shared Facilities. Spare parts that are charged to inventory shall not be cost-shared until the spare part is placed in service at a Jointly-Owned facility.

6. Capital Budgets. Four years prior to the year costs are expected to be incurred, each Party shall provide to the other Party a forecast of capital budget expenditures related to the planned construction and operation activities of the Cost Shared Facilities except for the excluded facilities identified by a footnote in Exhibit C. This forecast shall be provided to the other Party on or before July 1 of each year and shall include updates of any estimated costs for the next 3 years. The Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities. This notification requirement shall not apply to emergency replacement of equipment.

7. Payment Provisions.

(a) Payments made under this Amendment shall be made in accordance with provisions in this section 7 and shall be made for the following periods:

(1) Actual Costs for Cost Shared Facilities incurred for Prior Costs;

(2) Advances and Actual Costs for the Cost Shared Facilities incurred for the period from January 1, 1992, through the last month listed in the cash flow exhibits, Exhibits G and H by monthly invoices in accordance with Section 7(c) Progress Payments;

(3) Payment or refund for the final accounting of Actual Costs in accordance with Section 7(d) Final Accounting of Costs;

(4) Payment for future capital replacements in accordance with Section 7(e) and tables to Exhibit J; and,

(5) Payment for Operation and Maintenance shall be in accordance with Exhibit K.

Bonneville and PacifiCorp shall specify the financial institution and account number in a written notice to each other at the invoicing address and provide updates as necessary for the transfer of funds. Each invoice shall include a reference to Contract No. DE-MS79-86BP92299 and an invoice number.

(b) Prior Costs Payments. Bonneville shall pay PacifiCorp by check or electronic transfer of funds within 30 days after the date of an itemized invoice for PacifiCorp's Prior Costs, $10,047,832.97 as agreed to by the Parties pursuant to the audit dated February 4, 1993. The date of such invoice shall be no earlier than the mailing date of such invoice. Such amount represents payment to PacifiCorp of Prior Costs through December 31, 1991, except for land and related land costs which may be subject to adjustment after Bonneville's receipt and review of all PacifiCorp's legal conveyance documents in accordance with Sections 8 and 14. Adjustments of Prior Costs as a result of PacifiCorp's final analysis of accounts performed for the final accounting of costs shall also be made upon mutual agreement of the Parties.

PacifiCorp shall pay Bonneville by check or electronic transfer of funds within 30 days after the date of an itemized invoice for Bonneville's Prior Costs, $4,920,877.92, as agreed to by the Parties pursuant to the audit dated December 31, 1992. The date of such invoice shall be no earlier than the mailing date of such invoice. Such amount represents payment to Bonneville of

Prior Costs through December 31, 1991, except for land and related land costs which may be subject to adjustment after PacifiCorp's receipt and review of all Bonneville's legal conveyance documents in accordance with Sections 8 and 14. Adjustments of Prior Costs as a result of Bonneville's final analysis of accounts performed for the final accounting of costs shall also be made upon mutual agreement of the Parties.

(c) Progress Payments. Each Party shall make monthly payments to the other Party for the Cost Shared Facilities incurred after January 1, 1992, in accordance with Sections 7(c)(1) and 7(c)(2) below. The initial invoice shall also include amounts due for all past months from January 1, 1992, through the Amendment Effective Date with a credit for the amount previously paid under the Interim Payment Agreement.

(1) Payment by PacifiCorp. Each month Bonneville shall submit an itemized invoice to PacifiCorp (Jerry Walker, 800 PSB, 920 SW. Sixth Avenue, Portland, Oregon 97204) for the next month's Advance, in accordance with Exhibit G, and any adjustments for the previously invoiced Advance amounts when Actual Costs for such month(s) are known. The date of such invoice shall be no earlier than the mailing date of such invoice. The Actual Costs adjustment shall identify the Cost Shared Facilities with an itemization of cost elements by Bonneville work functions (i.e., materials, design, construction, etc.)

PacifiCorp shall pay Bonneville by check or electronic transfer of funds within 30 days after the date of the invoice. Should the 30th day be a Saturday, Sunday, or holiday, as observed by PacifiCorp, then the due date shall be the next following business day.

A credit balance on an invoice of $100,000 or less shall be carried forward to the next month's invoice. A credit balance on an invoice of

more than $100,000 shall be refunded to PacifiCorp by check or electronic transfer of funds within 15 days of the date of Bonneville's credit invoice. A refund of the credit balance shall also be made, regardless of the amount, if the sum of the remaining Advances is less than the credit balance.

(2) Payment by Bonneville. Each month PacifiCorp shall submit an itemized invoice to Bonneville (Bonneville Power Administration, P.O. Box 3621 - DSAC, Portland, Oregon 97208-3621) for the next month's Advance in accordance with Exhibit H, and any adjustments for the previously invoiced Advance amounts when Actual Costs for such month(s) are known. The date of such invoice shall be no earlier than the mailing date of such invoice. The Actual Costs adjustment shall identify the Cost Shared Facilities with an itemization of cost elements (i.e., labor, materials, purchase services, miscellaneous and overheads, etc.)

Bonneville shall pay PacifiCorp by check or electronic transfer of funds within 30 days after the date of the invoice. Should the 30th day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day.

A credit balance on an invoice of $100,000 or less shall be carried forward to the next month's invoice. A credit balance on an invoice of more than $100,000 shall be refunded to Bonneville by electronic transfer of funds within 15 days of the date of PacifiCorp's credit invoice. A refund of the credit balance shall also be made, regardless of the amount, if the sum of the remaining Advances is less than the credit balance.

(d) Final Accounting of Costs. Within 3 years after the date of commercial operation of all the Jointly-Owned and Cost Shared Facilities,

Bonneville and PacifiCorp shall each prepare a final accounting of all Actual Costs incurred for the Cost Shared Facilities identified in Exhibit C.

Each Party shall prepare an itemized invoice for the total final Actual Costs with either a refund or payment due the other Party. Payments and refunds shall be made in accordance with Sections 7(c)(1) and 7(c)(2).

(e) Payment Provisions for Capital Replacements:

(1) For reimbursable Capital Replacements, either Party shall prepare, for execution by the Parties hereto, an additional table to Exhibit J each time the Parties hereto agree that facilities shall be added or replaced to those facilities identified in Exhibit C to the Intertie Agreement. Those facilities identified by footnote one in Exhibit C shall be exempt from further cost sharing on capital replacements. Each table shall specify the facilities to be installed, the work to be performed by each Party, and the estimated costs to be borne by each Party. Payments shall be made as provided in each table to Exhibit J for the work to be performed in amounts and at times requested by the Party due reimbursement.

(2) Upon execution by the Parties hereto, new tables to Exhibit J shall be attached to and deemed to be a part of this Amendment to the Intertie Agreement and shall be effective on the date specified therein.

(f) Operation and Maintenance Charges. Effective on December 18, 1992, and pursuant to Exhibit K, PacifiCorp shall pay Bonneville for 50 percent of the operation and maintenance of the three Alvey 500 kV power circuit breaker terminals. Such operation and maintenance charge shall be included in PacifiCorp's monthly Wholesale Power Bill and shall remain in effect until such time the Alvey 500 kV facilities are available for commercial operation as part of the AC Intertie. Effective on December 18, 1992, PacifiCorp shall

pay Bonneville 35 percent of the operation and maintenance of the series capacitors at the Sycan Compensation Station (Sycan) pursuant to Exhibit K. Such operation and maintenance charge shall be included in PacifiCorp's monthly Wholesale Power Bill and shall remain in effect until such time as the Alvey-Meridian transmission line is available for commercial operation as part of the AC Intertie. However, the payments for such operation and maintenance charges shall be provided for in the follow-on Operations and Maintenance Agreement from the date of commercial operation as part of the AC Intertie.

(g) Disputed Billing. In the event of a disputed billing, full payment shall be made with written notification of the disputed amount. If it is determined that an adjustment is required, the adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in Section 7(h) below.

(h) Late Payment by Bonneville or PacifiCorp. Invoices not paid in full on or before the close of business on the due date shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

8. Audit. Each Party, at its expense, shall have the right to review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings, investments, and costs of the Cost Shared Facilities. Any audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The foregoing shall not be construed to permit either Party to conduct a general audit of the other Party's records beyond those needed to perform an audit of the Cost Shared

Facilities. The Party being audited agrees to cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of 3 years following the last day of the fiscal year in which such cost was incurred or the final accounting of costs under this Amendment. If either Party does not audit the costs of the other Party for fiscal years 1992, 1993, or 1994, prior to the completion of the final accounting of costs, the right to audit those costs shall extend for a period of 3 years after the date of completion of the final accounting of costs. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

The Party being audited shall be notified promptly in writing of any exception taken as a result of an audit after completion of the audit. The Party being audited shall have 30 days to review the notice of exception. If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) within 30 days of such agreement to the other Party. In the event of late payment, the Late Payment Provisions of Section 7(h) shall apply to amounts not paid in full by the due date.

Prior to the Amendment Effective Date, the Parties performed audits of each Party's Prior Costs. Such costs shall not be subject to additional audits, except for the audit of supporting documentation required for accounting adjustments that may have originated from the Prior Cost audit. However, both Parties reserve the right to review Prior Costs billed under Section 7(b) for land and related land costs. Any Prior Cost adjustment shall be determined after a Party receives and reviews all legal conveyance documents

from the other Party. The results of the Prior Cost audits and resulting amounts due are reflected in Section 7(b).

9. Ownership of Facilities.

(a) Transfer of legal ownership pursuant to Amendatory Agreement No. 2 shall be effective at such time the facilities are energized and made available for commercial operation as part of the AC Intertie and shall remain in effect so long as any facilities of the Alvey-Meridian Line are in existence and operable and shall survive the term of the Intertie Agreement.

(b) All Jointly-Owned equipment, facilities, and capital spare parts shall be identified as such with co-ownership tags and signs. Either Party, at such Party's sole expense, shall provide the tags and signs.

10. Operation and Maintenance of Facilities.

(a) The Parties agree that Section 1(b) to Amendment No. 1 to the Intertie Agreement is hereby replaced in its entirety by the following:

"(b) Maintenance and Operation. PacifiCorp shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors; the terminal facilities at Meridian Substation for the Dixonville-Meridian Line, including the series capacitors; the Alvey-Meridian Line; PacifiCorp's relays, digital fault recorder, and SCADA remote terminal unit at Captain Jack Substation; the loop-in of PacifiCorp's Malin-Meridian 500 kV Line at Captain Jack Substation; PacifiCorp's relays installed at Summer Lake and Malin Substations; PacifiCorp's Dead-End Tower installed at Sycan as part of the Sycan Addition; and all communication facilities owned by PacifiCorp. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors; all the facilities at Captain Jack Substation other than PacifiCorp's relays,

digital fault recorder and SCADA remote terminal unit; the Sycan Addition other than PacifiCorp's Dead-End Tower; and all communication facilities owned by Bonneville. The Parties shall exchange maintenance standards with each other and shall carry out their respective maintenance responsibilities according to Prudent Utility Practices. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Exhibit C, as amended."

(b) The Parties shall use best efforts to develop and execute a new AC Intertie Operation and Maintenance Agreement for the facilities identified in Exhibit C by December 1993. During the period between the energization date of any of these facilities and the date that such facilities are available for commercial operation as part of the AC Intertie, operation and maintenance shall be provided by the Parties as identified in Section 10(a) above and Exhibit C to the Intertie Agreement, without charge to the other Party, except for those facilities identified in Section 7(f) of this Amendatory Agreement.

11. Environmental Requirements.

(a) Historic Contamination. Neither Party shall be liable for any fines, penalties and assessments, costs for investigation, response, removal and remediation, arising from Historic Contamination of facilities owned by the other Party or operated by the other Party prior to becoming Jointly-Owned facilities pursuant to this Amendment.

(b) Disclosure of Information. Bonneville shall provide PacifiCorp, within 90 days after the Amendment Effective Date, a summary of all known and suspected Hazardous Substance release, spill and disposal events at facilities described herein which occurred prior to the Amendment Effective Date. PacifiCorp may request and Bonneville shall provide, for the purpose of establishing baseline contamination data for the facilities transferred to

Jointly-Owned facilities pursuant to this Amendment, all information including records, files and documentation pertaining to all known and suspected Hazardous Substance release, spill and disposal events at such transferred facilities. Such information shall also include correspondence, requests, determinations, findings and orders made by or to Federal, state or local agencies in connection with known and suspected Hazardous Substance release, spill and disposal events.

PacifiCorp shall provide Bonneville, within 90 days after the Amendment Effective Date, a summary of all known and suspected Hazardous Substance release, spill and disposal events at PacifiCorp's facilities described herein which occurred prior to the Amendment Effective Date. Bonneville may request and PacifiCorp shall provide, for the purpose of establishing baseline contamination data for the facilities transferred to Jointly-Owned facilities pursuant to this Amendment, all information including records, files, and documentation pertaining to all known and suspected Hazardous Substance release, spill and disposal events at such transferred facilities. Such information shall also include correspondence, requests, determinations, findings and orders made by or to Federal, state or local agencies in connection with known and suspected Hazardous Substance release, spill and disposal events.

(c) Emergency Environmental Responsibility. The Party in operational control of a Jointly-Owned facility shall prepare and obtain approval required for emergency response plans for Hazardous Substance releases from all appropriate Federal, state and local agencies and shall be responsible for management and implementation of all laws and regulations pertaining to Hazardous Substances at the Jointly-Owned facility. Costs associated with

approval and implementation of such plans shall be included in the Actual Costs.

12. Capital Replacements. Cost sharing for replacement of facilities specified in Exhibit C, due to obsolescence or major failure, shall be shared by the Parties according to the original cost share percentage of such facilities and in accordance with Exhibit J and Section 7(e) except for the excluded facilities identified by footnote one in Exhibit C.

13. Decommissioning Costs. The Parties shall pay decommissioning costs of Jointly-Owned facilities in accordance with their ownership shares as specified in Exhibit C. Proceeds from the disposal of Jointly-Owned surplus property or facilities shall be equitably distributed or allocated to the Parties in accordance with their ownership shares as specified in Exhibit C. The cost-sharing of decommissioning costs shall survive the term of the Intertie Agreement.

14. Land and Improvements. Right-of-way and land costs for the Alvey-Meridian Line and for Alvey, Dixonville, Meridian, and Captain Jack Substations will be cost-shared consistent with Exhibit C and the following principles. Bonneville's land maps are attached as Exhibit I, 1 and 2. PacifiCorp's land drawings attached as Exhibit I 3 through I 9 represent the Parties intent using such generic examples.

(a) Alvey-Spencer Line. Right-of-way and/or land costs shall conform to the following:

(1) If Bonneville acquires new right-of-way (Easement Rights) on land not owned by Bonneville, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost to purchase such Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, pages 1 of 13 and 2 of 13, provide an example of such right-of-way.

(2) If PacifiCorp uses existing right-of-way (Fee-Owned Land), Bonneville will not share in the cost and will receive easement for access only for such Fee-Owned Land. This includes land owned by PacifiCorp adjacent to PacifiCorp's Spencer Switchstation (Section 22, Township 18 South, Range 3 West, W.M.).

(b) Spencer-Meridian 500 kV Line. Right-of-way and/or land costs shall conform to the following:

(1) If PacifiCorp acquires new right-of-way (Easement Rights) on land not owned by PacifiCorp, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost to purchase such Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, page 4 of 13, page 6 of 13, and page 7 of 13, provides examples of such right-of-way.

(2) If PacifiCorp acquires new land (Fee-Owned Land) for the sole purpose of providing right-of-way for the Spencer-Meridian Line, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost of acquiring such Fee-Owned Land and will each receive 50 percent ownership of the Fee-Owned Land actually utilized to provide the necessary right-of-way. This includes land that is excess to normal right-of-way requirements which was purchased to provide necessary right-of-way and has been rendered non-marketable due to the transmission line construction. Exhibit I, page 5 of 13 and page 8 of 13, provides examples of such right-of-way.

(3) If PacifiCorp acquires new land (Fee-Owned Land) to provide right-of-way for the Spencer-Meridian Line, which it intends to market or retain portions thereof for its own purposes, PacifiCorp will provide and maintain Easement Rights for the portion of such Fee-Owned Land necessary

for such right-of-way. Bonneville and PacifiCorp will each pay 50 percent of the Actual Costs to provide Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, page 5 of 13, provides an example of such right-of-way.

(4) If PacifiCorp uses existing right-of-way (Easement Rights or Fee-Owned Land), Bonneville will not share in the cost and will receive easement for access only in addition to an ownership interest in the Alvey-Meridian 500 kV Transmission Line.

(5) If PacifiCorp secures any permits for right-of-way across public lands, Bonneville and PacifiCorp will each pay 50 percent of the Actual Costs associated with such permits and will each receive 50 percent interest in such permits. Exhibit I, page 7 of 13, provides an example of such right-of-way.

(6) If, in the future, PacifiCorp markets any of the Fee-Owned Land as described in Section 14(b)(2) herein for which Bonneville has paid PacifiCorp 50 percent of the Actual Costs, Bonneville will receive 50 percent of the sale proceeds, less expenses.

(c) Substations. Right-of-way and/or land costs shall conform to Exhibit C and the following:

(1) Alvey Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 10 of 13, and each Party will receive a 50 percent ownership.

(2) Dixonville Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 11 of 13, and each Party will receive a 50 percent ownership.

(3) Meridian Substation. Land will not be cost-shared jointly on the existing land as shown in Exhibit I, page 12 of 13. Bonneville will receive Easement Access only.

(4) Captain Jack Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 13 of 13, and PacifiCorp will receive a 100 percent ownership of such specific area.

(d) Title Transfer. Title and easement rights will be transferred by and to the Parties by a recordable conveyance document agreeable to both Parties after energization of the Alvey-Meridian Line.

To accomplish this, each Party will provide the other a copy of each recorded conveyance instrument and all permits obtained. Each instrument will be identified by category Exhibit I, page 4 of 13 through page 9 of 13. A full set of property maps will also be provided by each Party to the other depicting ownership acquisition. Both acquisition documents and a full set of property records (Plans) will be given by each Party to the other within 30 days after execution of this Amendment.

15. Notices. Any notice required to be served in accordance with the terms of this Agreement, shall be in writing and sent by registered or certified mail, return receipt requested, to the appropriate address listed below:

Bonneville Power Administration
P.O. Box 3621 - P
Portland, OR 97228-3621

PacifiCorp
Jerry Walker, 800 PSB
920 SW. Sixth Ave.
Portland, OR 97204

16. Liability.

(a) Bonneville and PacifiCorp assert that neither Party is the agent or principal for the other or that they are partners or joint venturers; and the Parties agree that they will not represent to any other party that they act in The capacity of agent or principal for the other. Any judgments in tort obtained against either Party shall not be an Actual Cost of the Cost Shared Facilities.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendatory Agreement in several counterparts.

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/type)

Title Vice President

Date March 16, 1993

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____

Name Randall W. Hardy
(Print/type)

Title Administrator

Effective Date March 16, 1993

(VSIO-PMTT-3568e)

Exhibit F, Page 1 of 2
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
Pacificorp
Effective at 2400 hrs
on the effective date

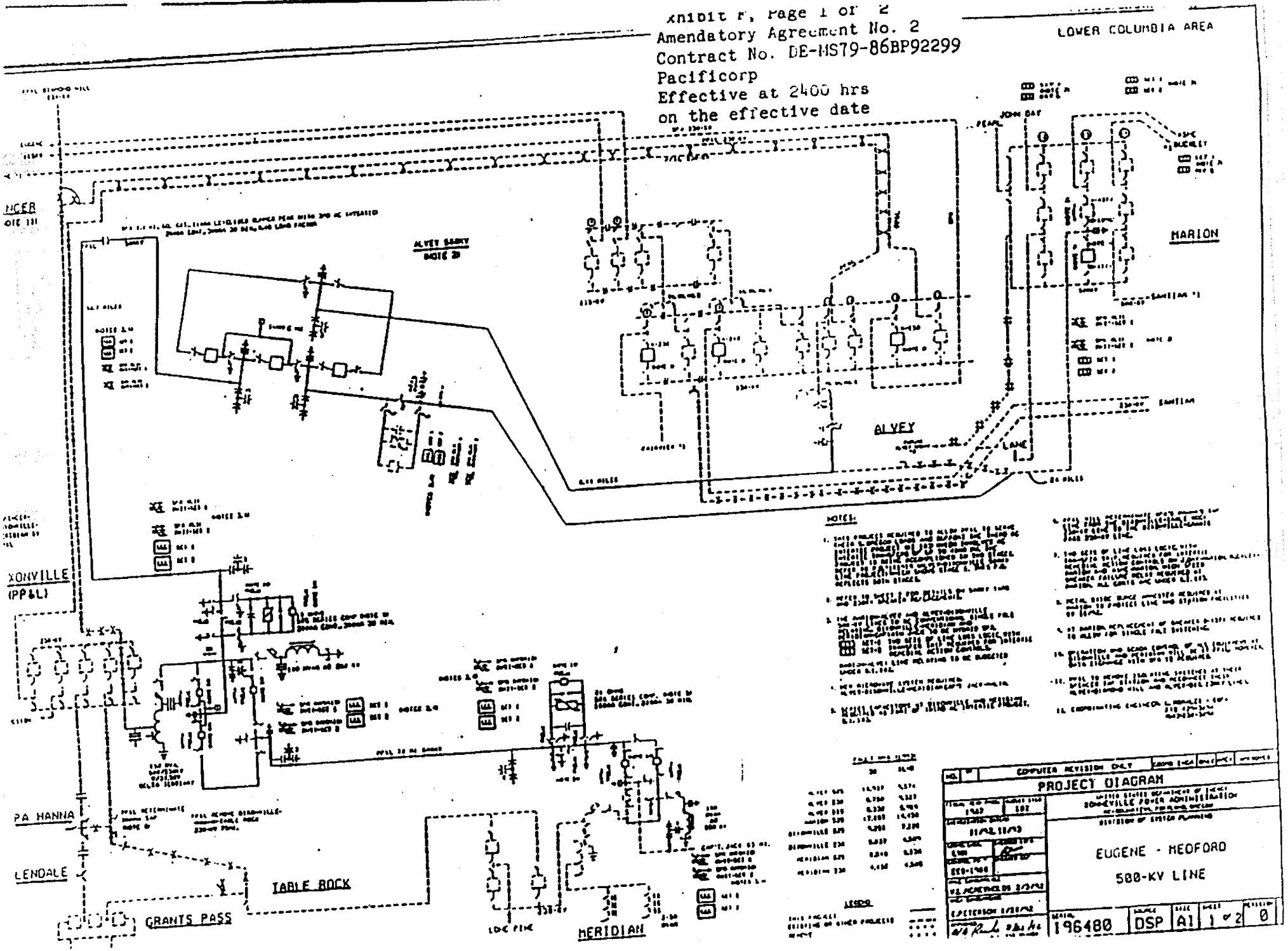
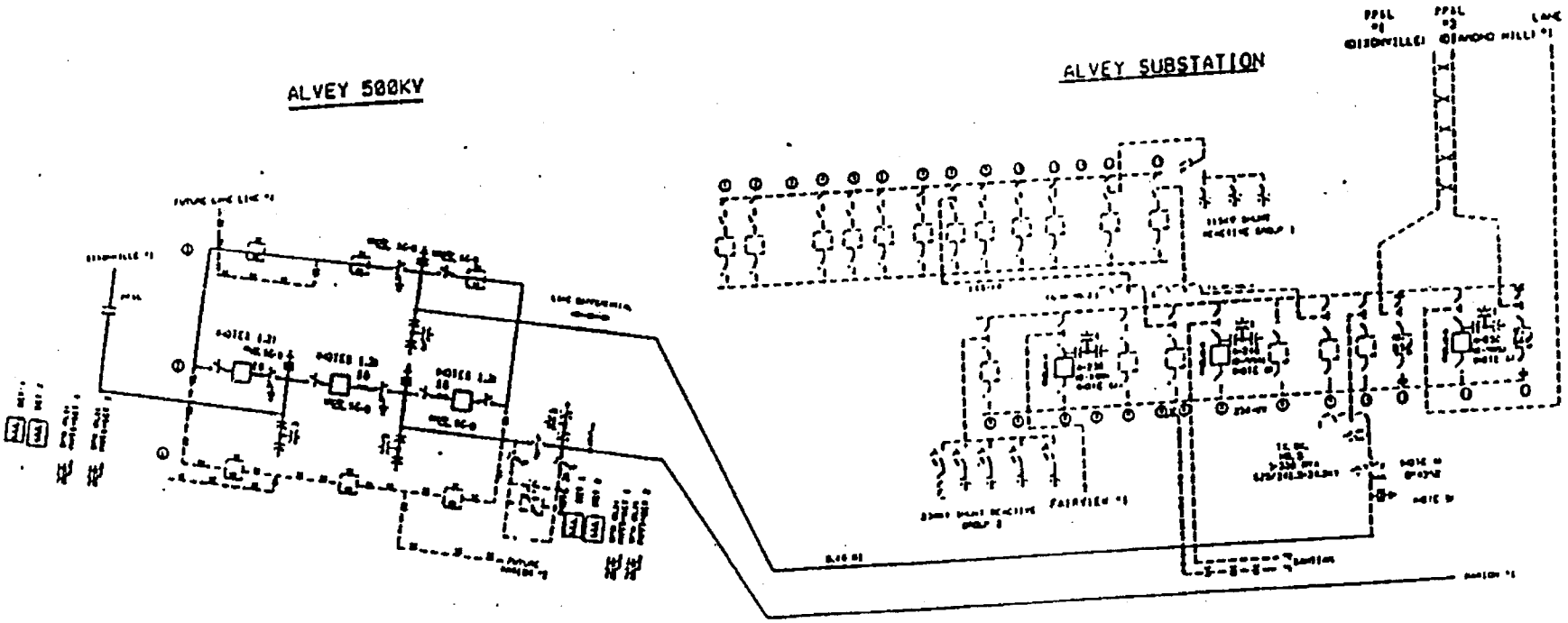


Exhibit F, Page 2 of 2
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
Pacificorp
Effective at 2400 hrs
on the effective date



FAULT MVA (1993)

	3Ø	LL-G
ALVEY 525	18927	9574
ALVEY 230	8356	9327
ALVEY 115	9336	8459

PROJECT DIAGRAM

EUGENE - MEDFORD
500-KV LINE
ALVEY SUBSTATION

196480 | DSP | A1 | 2 of 2

Bonneville Cash Flow
(Dollars in Thousands)

Year	Month	Advances
1992	January through September	$ 5,534
	October	3,047
	Less Interim Payment	(6,000)
	November	392
	December	220
1993	January	585
	February	585
	March	769
	April	750
	May	325
	June	132
	July	166
	August	166
	September	78
	October	73
	Total	$ 6,822

Source Document:
Bonneville Eugene-Medford Project Cash Flow Estimates
Prepared by J. Quinata, dated 1/25/93
Prior Costs are excluded.

(VS10-PMTT-3596e)

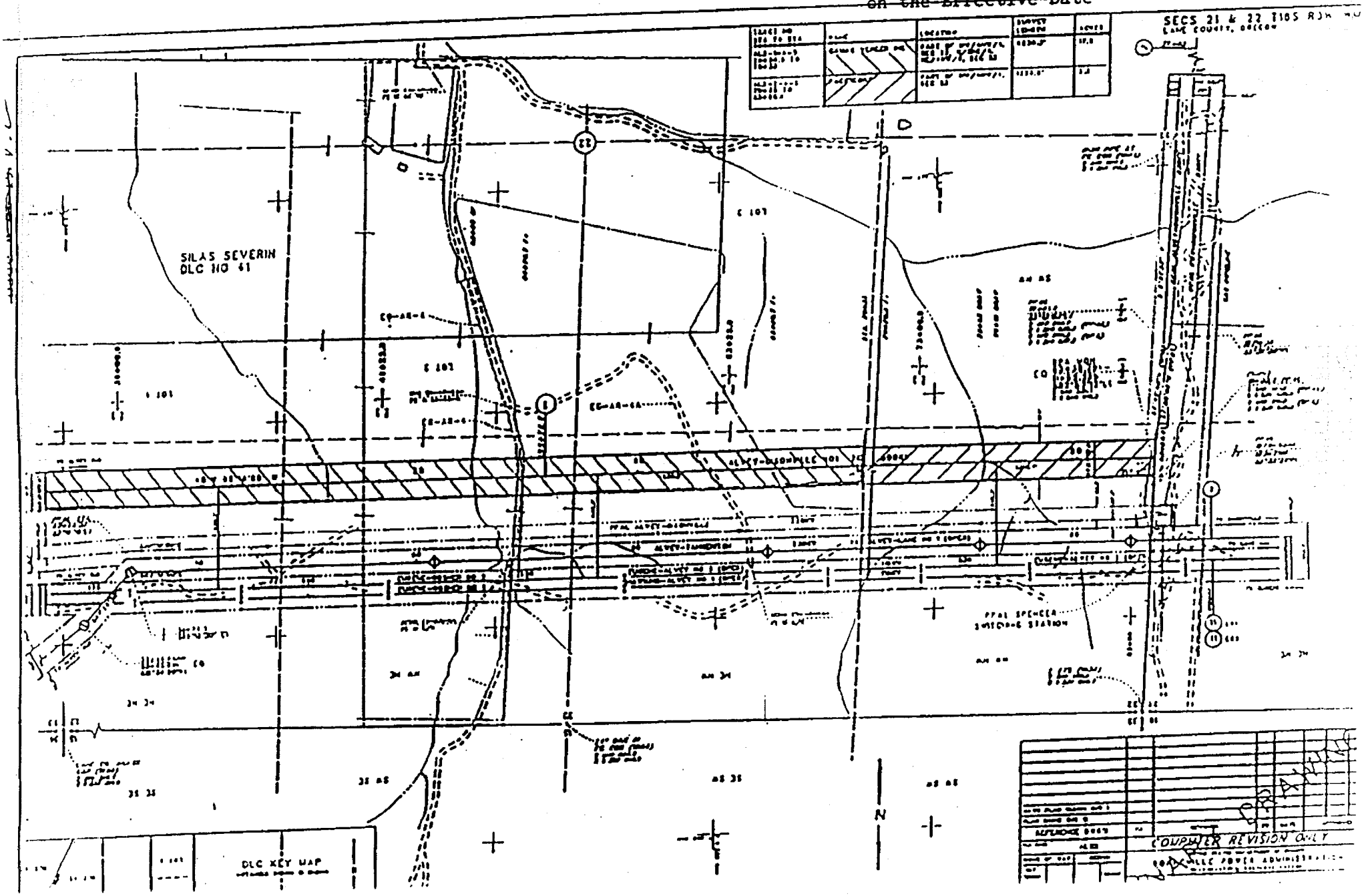
PacifiCorp Cash Flow
(Dollars in Thousands)

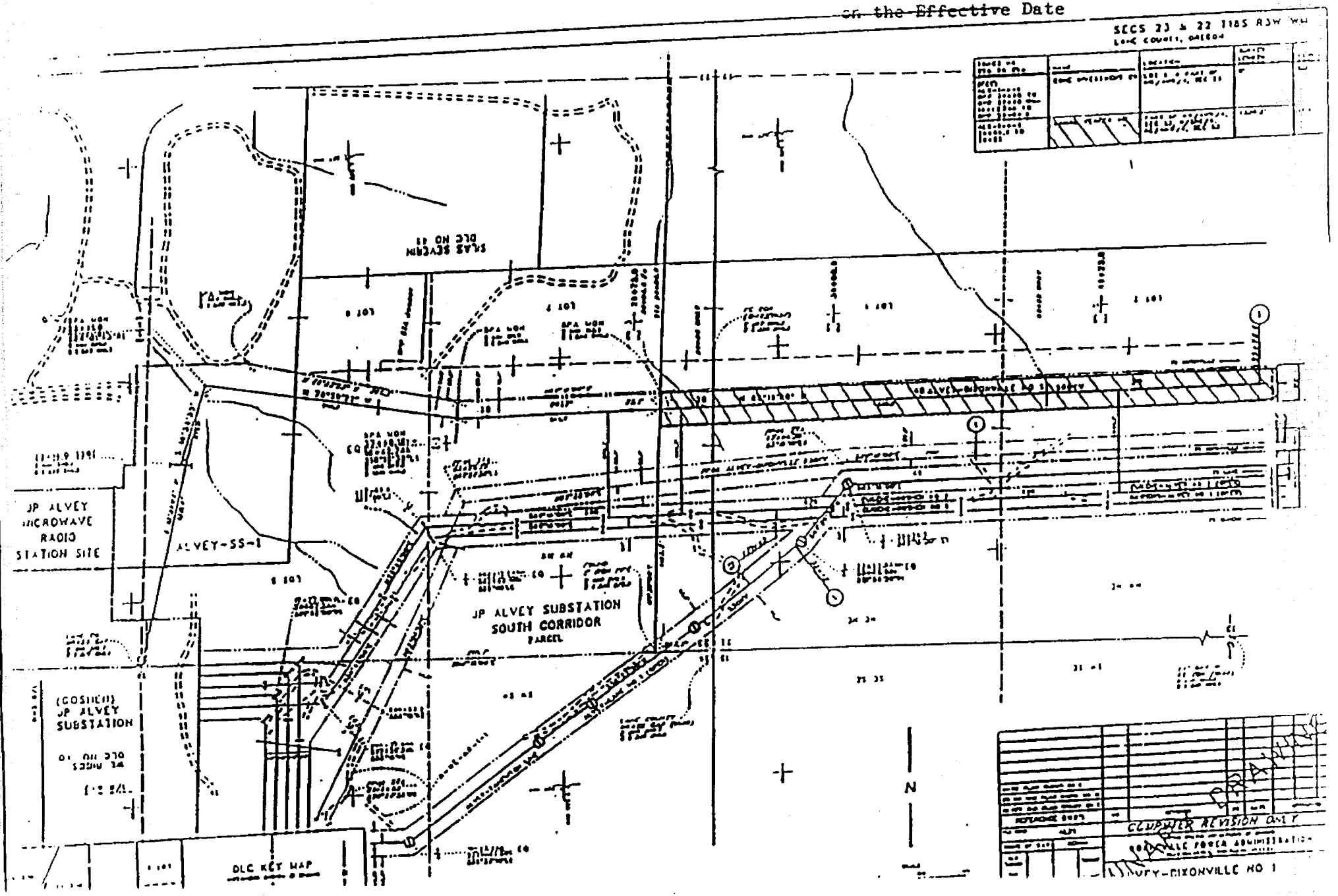
Year	Month	Advances
1992	January through September	$ 25,125
	October	3,897
	Less Interim Payment	(16,000)
	November	3,000
	December	4,500
1993	January	2,896
	February	1,995
	March	1,853
	April	1,788
	May	2,076
	June	2,103
	July	2,026
	August	1,800
	September	1,492
	October	1,579
	November	1,101
	December	234
	Total	$ 41,465

Source Document:
PacifiCorp: October 1992 Project Forecast
Southern Oregon 500 kV Project
Prepared by T. Jestrab, dated 12/31/92
Prior Costs are excluded.

(VS10-PMTT-3596e)

Exhibit I, Page 1 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
~~on the Effective Date~~




JP ALVEY MICROWAVE RADIO STATION SITE
ALVEY-SS-1
JP ALVEY SUBSTATION SOUTH CORRIDOR PARCEL
(PROPOSED) JP ALVEY SUBSTATION
DLC KEY MAP
N
ALVEY-DIXONVILLE NO 1

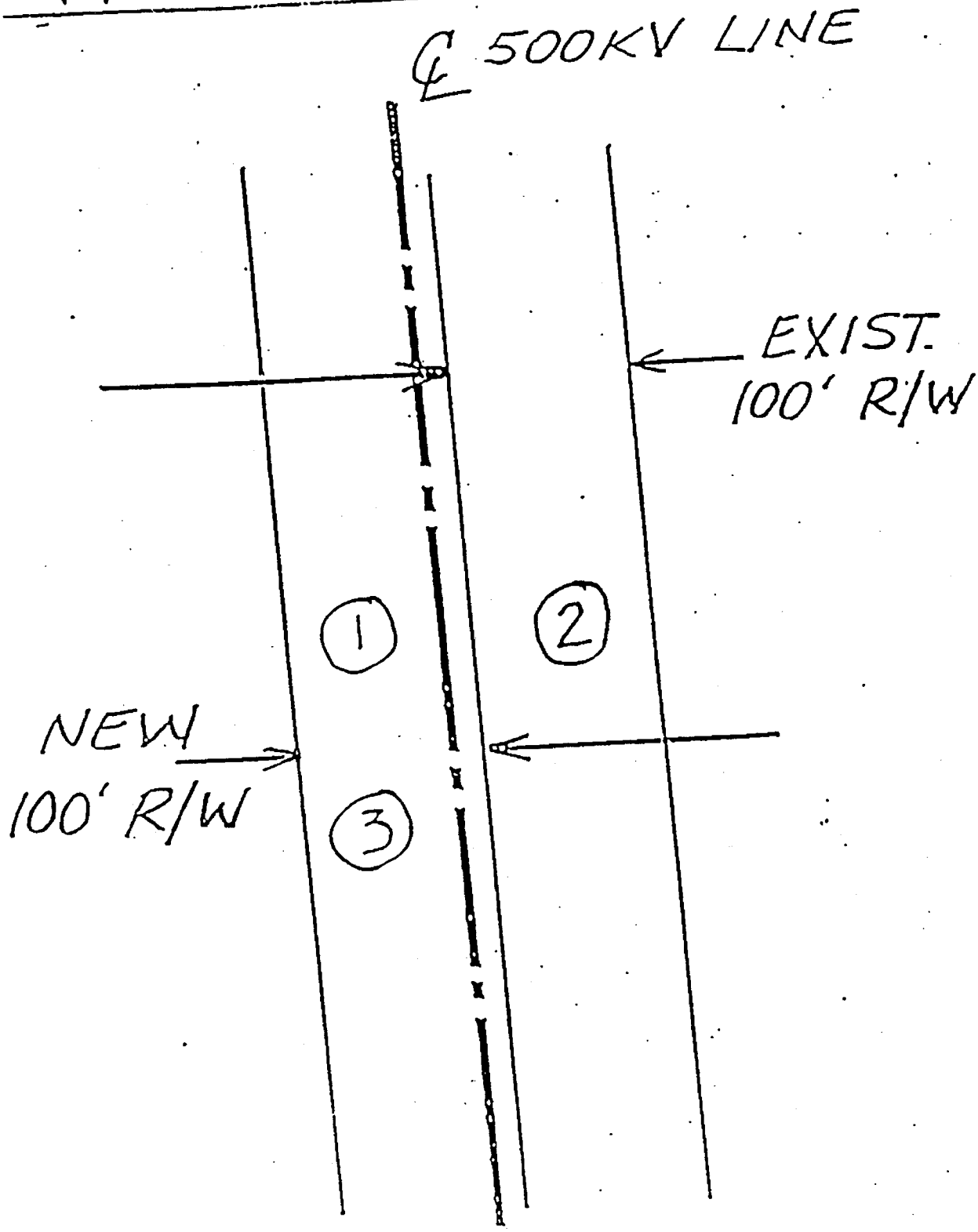
LEGEND

(1) - SHARED COST

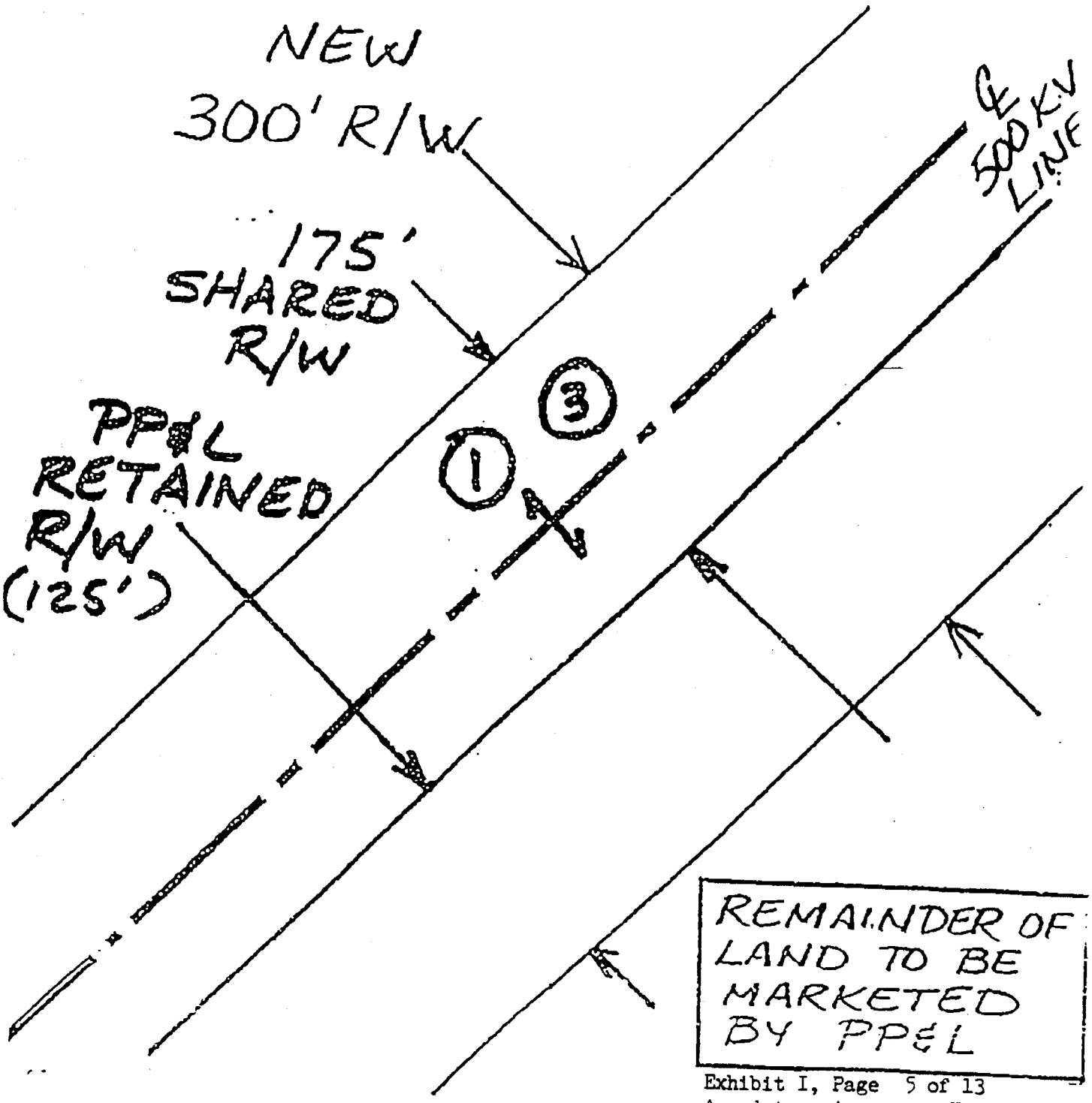
(2) - SHARED EASEMENT ACCESS ONLY

(3) - SHARED EASEMENT RIGHTS

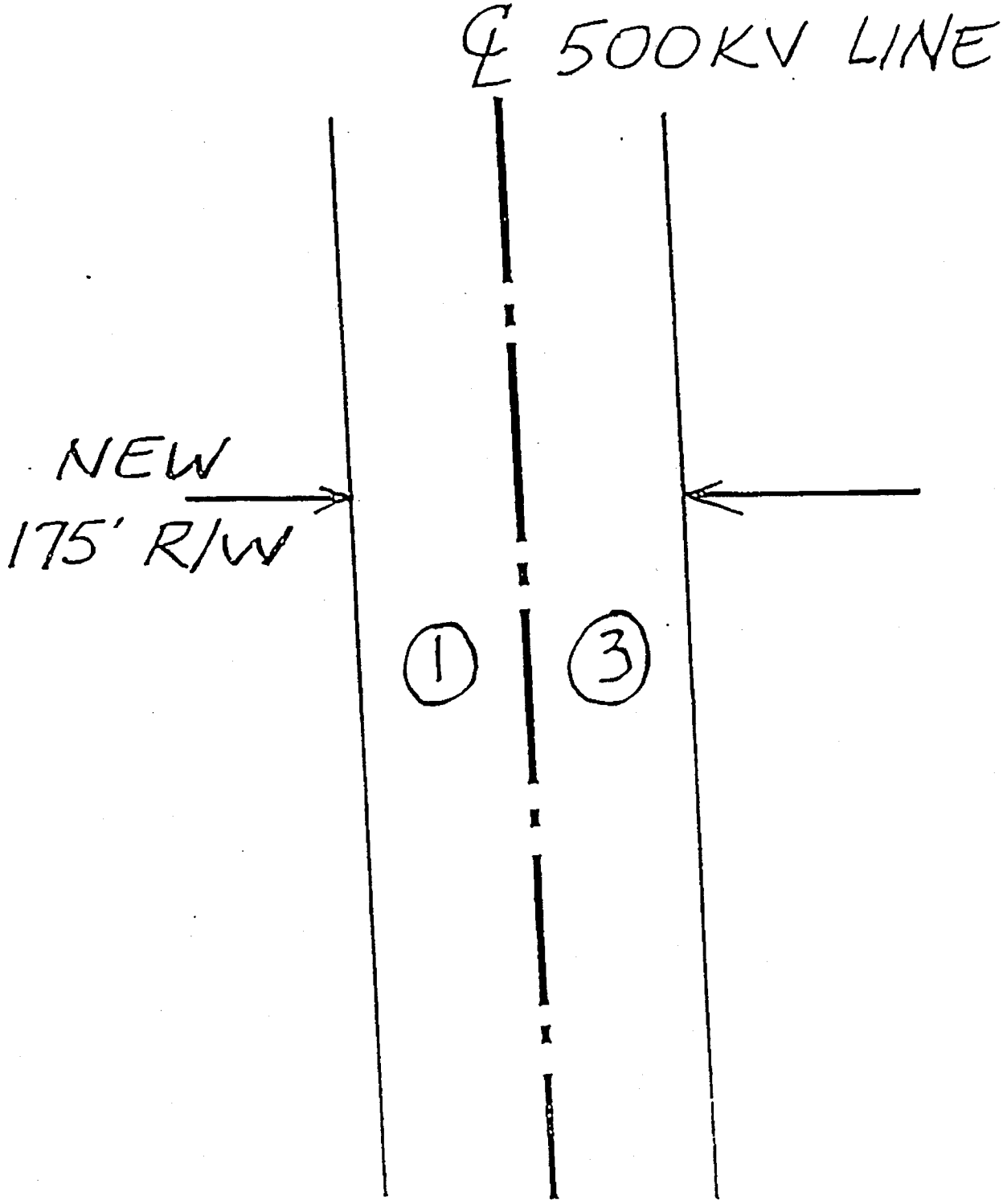
A. EXISTING R/W PRIVATE LAND - (1)



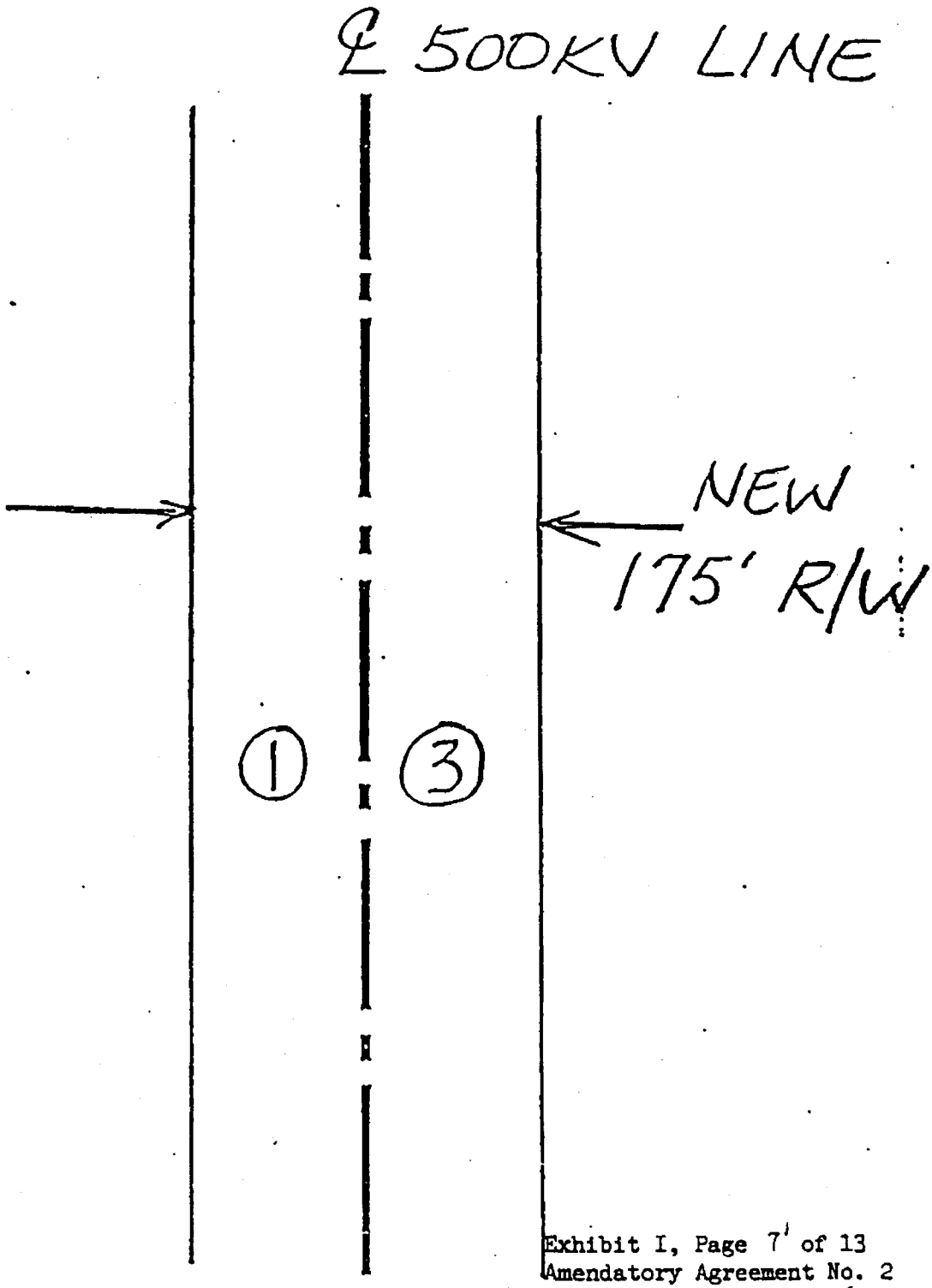
B. NEW R/W ON PP&L FEE OWNED LAND - (1



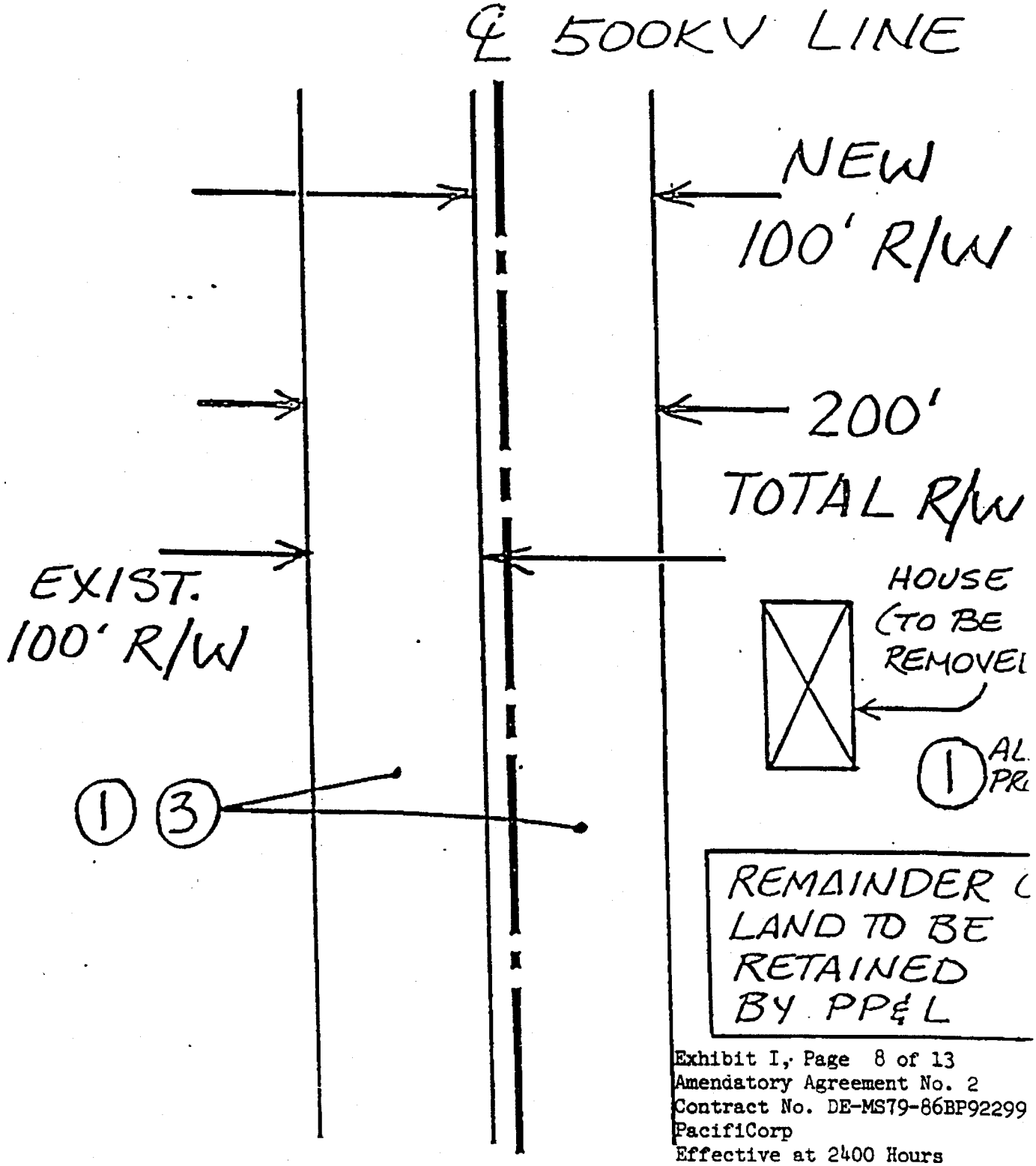
C. NEW R/W 82'
PRIVATE LAND



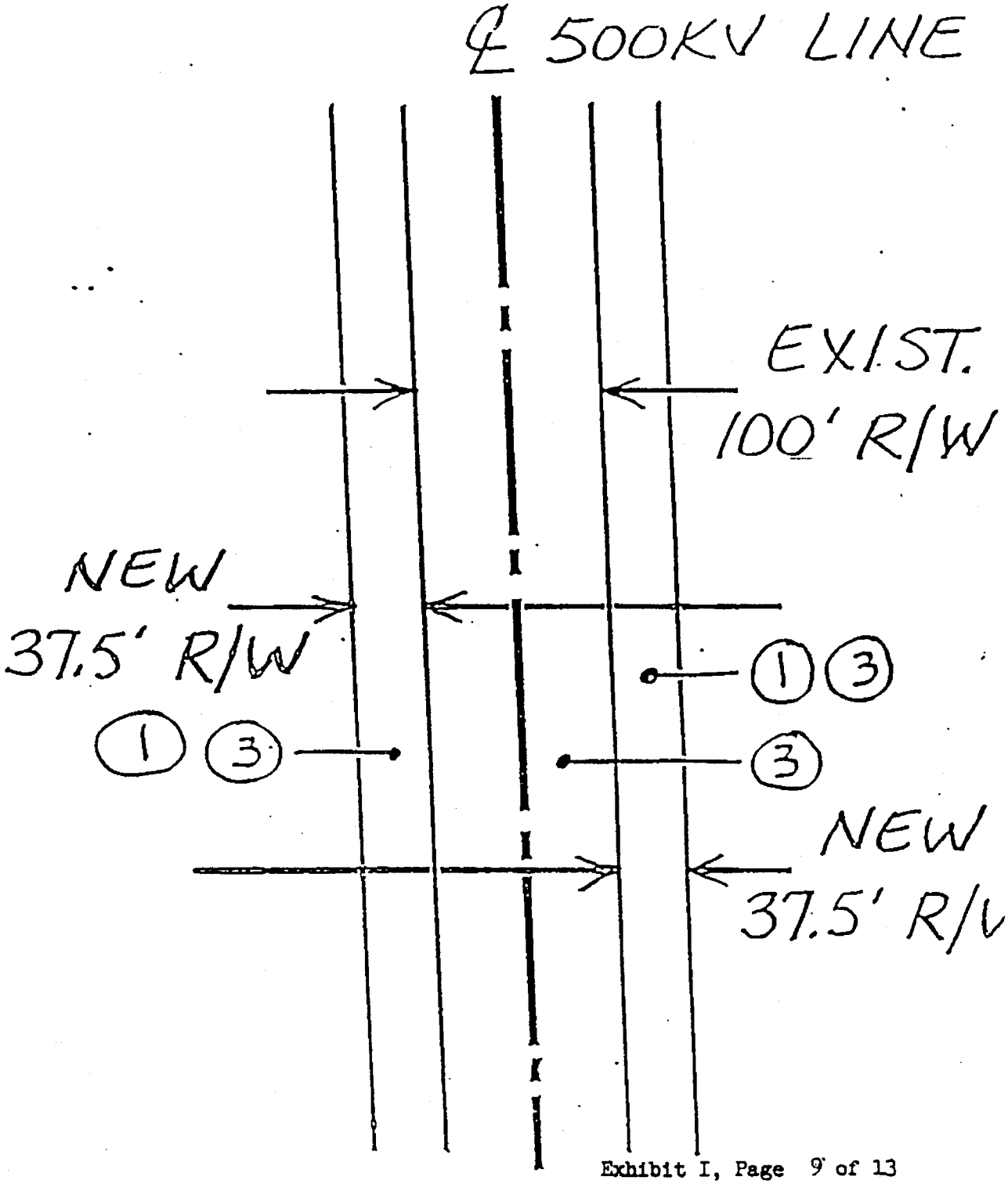
D. NEW R/W ON GOVERNMENT LANDS



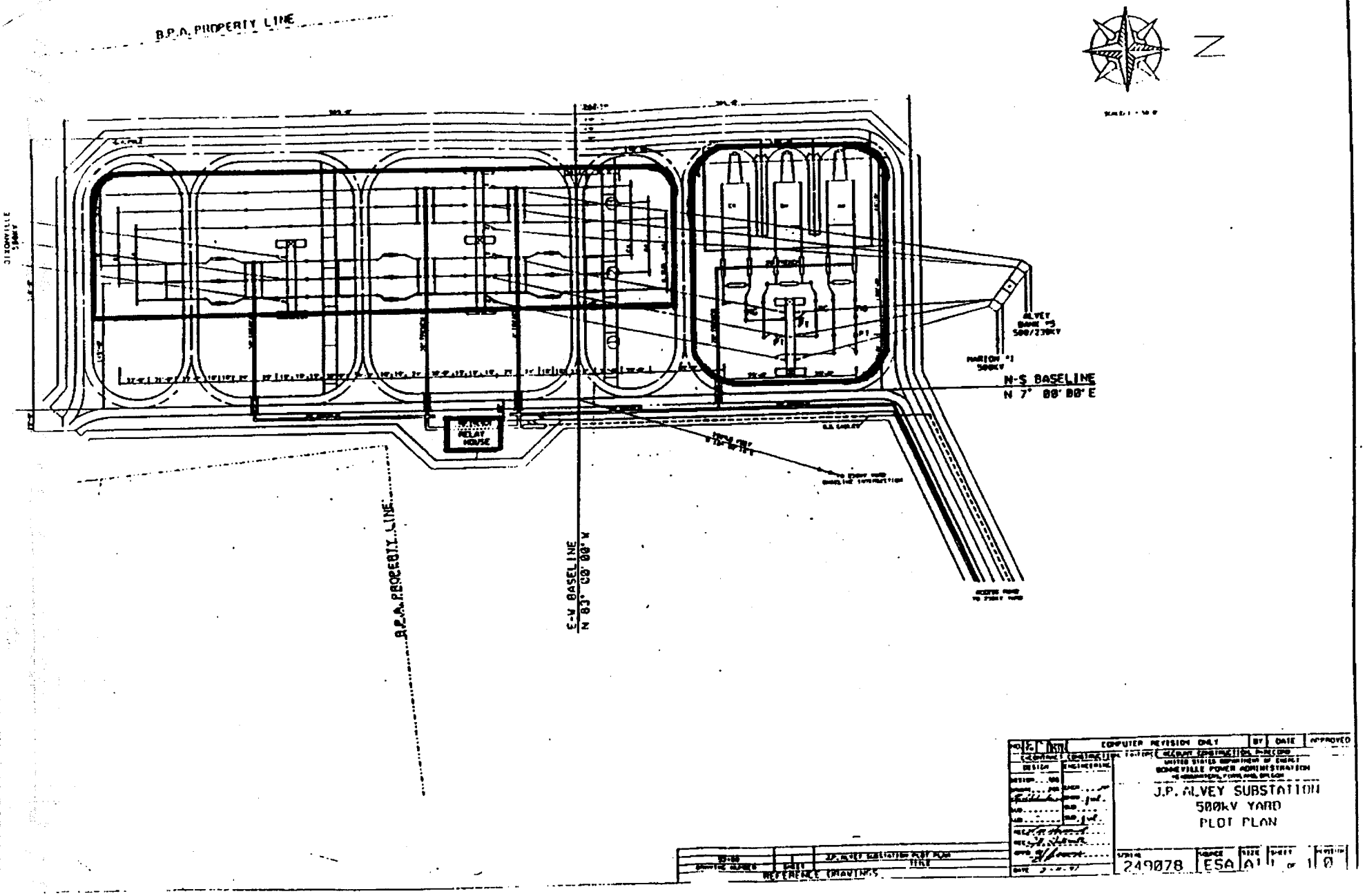
E. EXISTING R/W ON PP&L FEE OWNED LAND - (2)



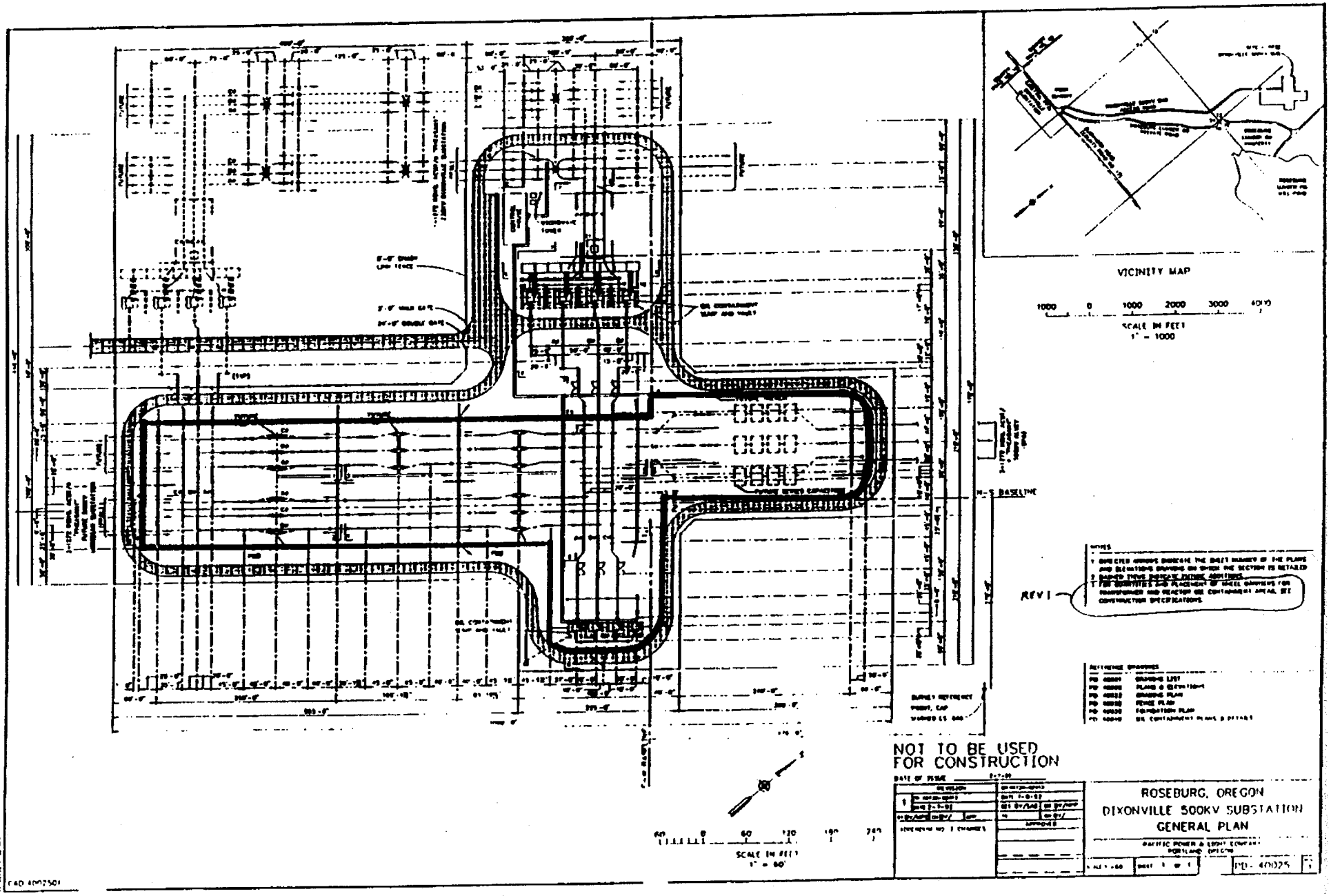
F. EXISTING R/W ON PRIVATE LAND - (2)



Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date



Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date



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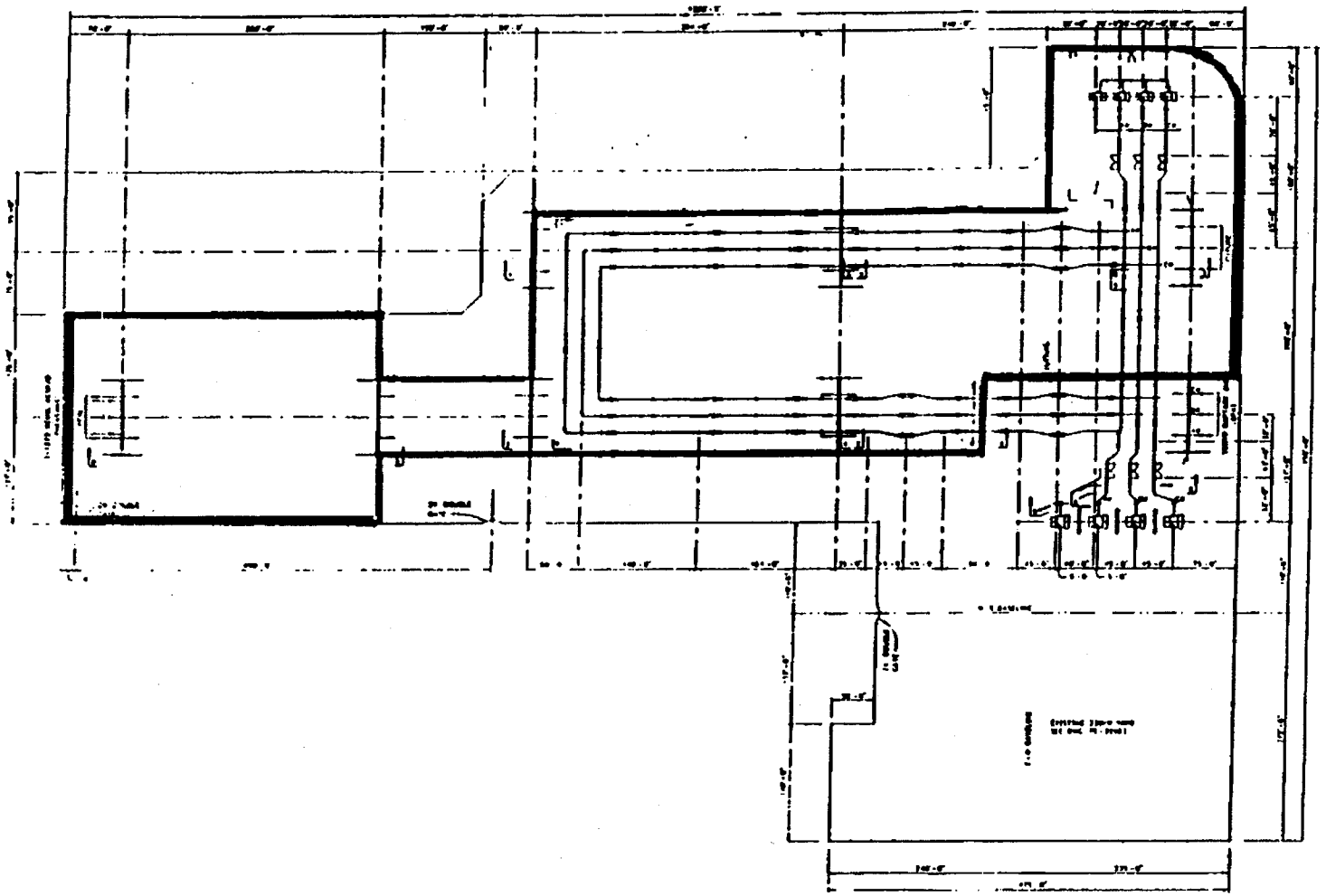
PacifiCorp
Effective at 2400 Hours
on the Effective Date

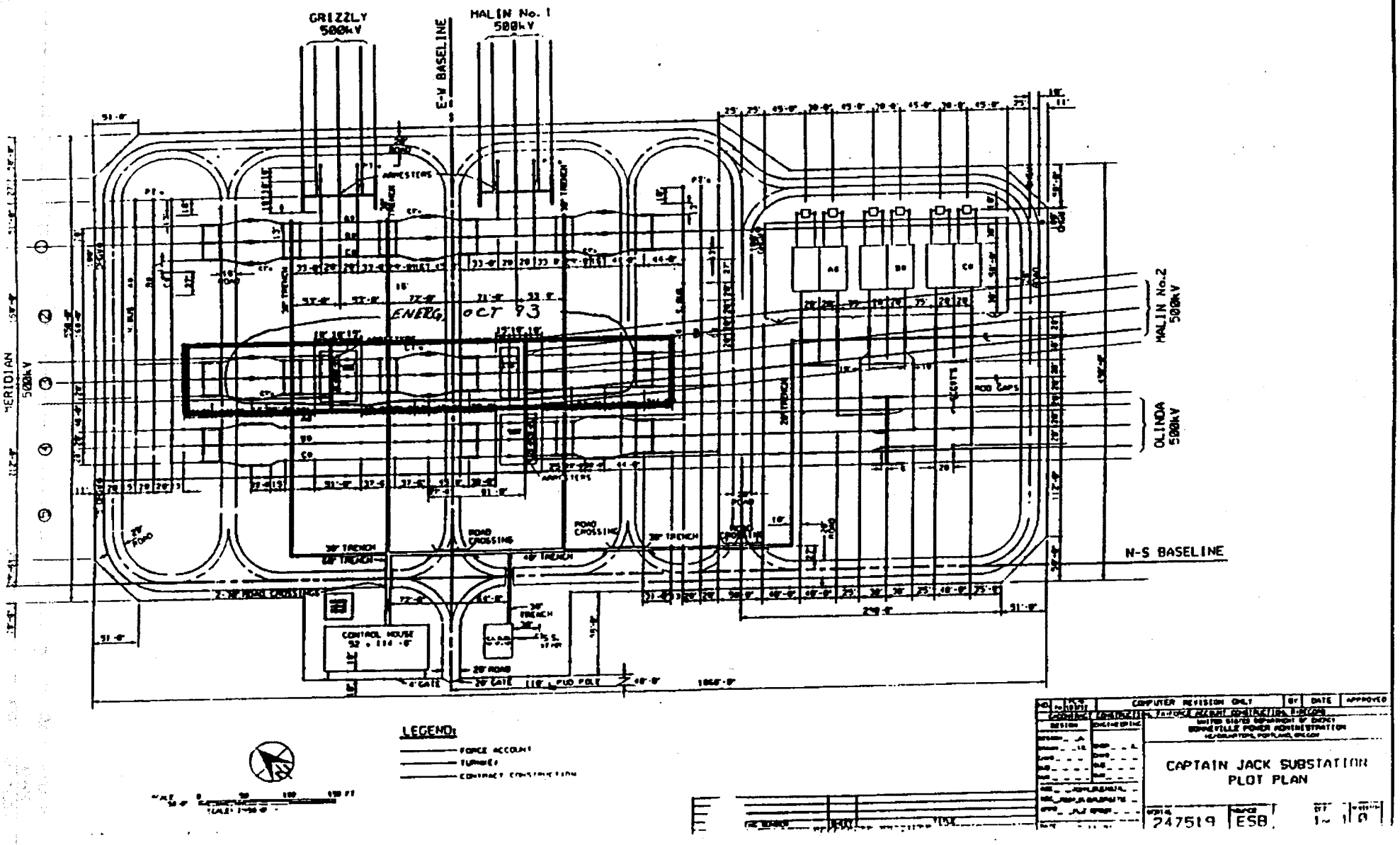


NOT TO BE USED
FOR CONSTRUCTION

MEDFORD, OREGON
MERIDIAN SUBSTATION
GENERAL PLAN

Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

16:36:19 28-OCT-91 ZH0:[051.157]247519S01.DGN



Capital Replacements

Either Party shall be able to initiate Capital Replacement projects to be added under this Exhibit as additional tables.

Calculation of O&M Charges

Facilities	Annual Operation and Maintenance Charge 1/	Annual Payment Due From PacifiCorp
Alvey (3) 500 kV PCB Terminals x ($46,018 terminal) Monthly Charge = $5752	$138,054	$69,027 2/
Sycan New Series capacitor bank (546 MVAR) in The Summer Lake-Malin 500 kV Line Monthly Charge = $5290	$181,381	$63,483 2/

1/ O&M Cost: From Bonneville Power Administration's Annual O&M Charges for Customer-Owned or Leased Facilities dated September 30, 1991.
2/ Effective December 18, 1992

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Alvey Substation						
♦ 3-500 kV breakers/CT's, buswork, towers, MOD's, PT's, arresters, associated grounding, conduit, control and power cables, site dev. including landscaping, station service equipment for the 3 breaker ring bus layout.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Environmental related work.	Bonneville	50/50	N/A	N/A	N/A	
♦ Series capacitors and auxiliaries.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Property acquired for 500 kV yard for Intertie purposes, excluding any additions, for future BPA projects.	Bonneville	50/50	50/50	Bonneville	42/58	Requires identification of boundaries. O&M costs subject to non-routine work. BPA to maintain at 100% BPA costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
♦ 500 kV Relay House building.	Bonneville	50/50	50/50	Bonneville	42/58	Future BPA/PP&L expansion will be done at 100% BPA/PP&L costs, otherwise 50/50 if Intertie related. General building maintenance should be at BPA discretion with 42/58 cost sharing.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Relaying and controls, data system equip. inside the 500 kV Relay House for the Alvey-Dixonville, Marion-Alvey and 500 kV Tie Line.	Bonneville	50/50	50/50	Bonneville	42/58	BPA has future rights for BPA projects at 100% BPA costs otherwise 50/50 if Intertie related. O&M at 42/58 as per this Exhibit C for Intertie related facilities. BPA to maintain.
♦ RAS related equip.	Bonneville					Refer to Contract #93039.
♦ Metering/Telemetering equipment on the Alvey-Dixonville Line.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to do the maintenance at BPA discretion.
500 kV Tie Line (Alvey 500-Tx. Bank #5)						
♦ Transmission related costs.	Bonneville	50/50	50/50	Bonneville	100/0	50/50 ownership means PP&L has 50% capacity rights on the Tie Line but not physical ownership. Transfer rights over Bank #5 are not covered here.
Marion-Alvey 500 kV Line Modifications						
♦ Transmission costs only. 1/	Bonneville	50/50	100/0	Bonneville	100/0	
34.5 kV Line Relocation						
♦ Transmission costs only. 1/	Bonneville	50/50	100/0	Bonneville	100/0	

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Alvey-Dixonville 500 kV Line						
♦ 1.4 mile Alvey-Spencer Tap Section. 2/	Pacific	50/50	50/50	Pacific	42/58	Applicable only to the ROW for Intertie purposes. Additional ROW at 100% BPA costs.
♦ Remaining 56.7 miles. 2/	Pacific	50/50	50/50	Pacific	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads must also be considered. Timber costs and revenues also to be included. 2/
Spencer Tap						
♦ Costs to reterminate the PP&L Alvey-Dix. 230 kV Line. 1/	Pacific	50/50	0/100	Pacific	0/100	
♦ Costs to reterminate the PP&L Alvey-Diamond Hill 230 kV Line. 1/	Pacific	0/100	0/100	Pacific	0/100	
Dixonville 500 kV Substation						
♦ 3-Breaker Ring Bus, 180 MVAR Reactor, arresters, grounding, conduit, control and power cables, site development, PT's, station service, isolating disconnect switches for 500 kV ring bus.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion).
♦ Series capacitors and auxiliaries.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion).

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ 500/230 kV Transformer and related 230 kV equipment. 1/	Pacific	0/100	0/100	Pacific	0/100	PP&L to maintain.
♦ Wetland mitigation and other environmental requirements.	Pacific	50/50	N/A	N/A	N/A	
♦ Property acquired for 500 kV yard for Intertie purposes, excluding any additional future PP&L projects and any property for PP&L's 500/230 kV transformer.	Pacific	50/50	50/50	Pacific	42/58	Requires identification of boundaries. O&M costs subject to non-routine work. PP&L to maintain at 100% PP&L costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
♦ 500 kV Control House building.	Pacific	50/50	50/50	Pacific	42/58	Future PP&L/BPA expansion will be done at 100% PP&L/BPA costs. Otherwise 50/50 if Intertie related. General building maintenance should be at PP&L discretion with 42/58 cost-sharing.
♦ Relaying and controls, data system equip.inside the 500 kV Control House, excluding that associated with PP&L's 500/230 kV transformer and 230 kV line position(s).	Pacific	50/50	50/50	Pacific	42/58	PP&L has future rights for PP&L projects at 100% PP&L costs. Otherwise 50/50 if Intertie related. O&M at 42/58 as per this Exhibit C for Intertie related facilities. PP&L to maintain.
♦ RAS related equipment.	Pacific					Refer to Contract #93039.
♦ Metering/Telemetering equipment on the Dixonville-Alvey Line.	Pacific	50/50	50/50	Pacific	42/58	PP&L to do the maintenance at PP&L discretion.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Dixonville-Meridian 500 kV Line						
♦ Transmission costs. 2/	Pacific	50/50	50/50	Pacific	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads/bridge must also be considered. Timber costs and revenues also to be included.
Hanna Tap Relocation						
♦ Transmission and switching modification costs. 1/	Pacific	50/50	0/100	Pacific	0/100	Ownership and O&M costs percentages reflect existing arrangements which will be maintained.
Table Rock Switching Station						
♦ Costs to remove existing station.	Pacific	50/50	N/A	N/A	N/A	Existing station is in the path of the new 500 kV Line.
♦ Costs to reconnect Line #71 to south portion of Line #54. 1/	Pacific	50/50	0/100	Pacific	0/100	
Meridian Substation						
♦ Installation of 2-500 kV breakers, CT's, 180 MVAR reactor, 2 Line PT sets, isolating disconnect switches, arresters, buswork, conduit, control and power cables, grounding, including site development for Intertie purposes.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion). 50/50 ownership does not apply to the existing property upon which such facilities lie.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Environmental related work associated with the 500 kV expansions required.	Pacific	50/50	N/A	N/A	N/A	
♦ Any additional new property required to support the project.	Pacific	50/50	50/50	Pacific	42/58	Requires identification of boundaries. O&M costs subject to non-routine work. PP&L to maintain at 100% PP&L costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
♦ Access road improvements or new access road.	Pacific	50/50	50/50	Pacific	0/100	
♦ Existing property. 1/	Pacific	0/100	0/100	Pacific	0/100	Boundaries to be identified that conveys future BPA rights of use.
♦ Series capacitors and auxiliaries.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion).
♦ Data system equip. inside the existing 500 kV Control House associated with the 2 breakers, 180 MVAR reactor, and the Meridian-Dixonville and Meridian-Captain Jack Lines.	Pacific	50/50	50/50	Pacific	42/58	PP&L to maintain.
♦ Relaying and controls for the Meridian-Dixonville 500 kV Line.	Pacific	50/50	50/50	Pacific	42/58	PP&L to maintain.
♦ Relaying and controls for the Meridian-Captain Jack #2 500 kV Line. 1/	Pacific	50/50	0/100	Pacific	0/100	PP&L to maintain. BPA retains the right to review any future relay replacements/modifications.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Any modification to the existing Control House or construction of a new Control House as a result of the Eugene-Medford projects.	Pacific	50/50	50/50	Pacific	0/100	Future PP&L/BPA expansion will be done at 100% PP&L/BPA costs, other-wise 50/50 if Intertie related. PP&L to maintain at their discretion.
♦ Construction of a new storage building.	Pacific	50/50	50/50	Pacific	0/100	Use of building to be audited later to confirm cost sharing percentages.
♦ RAS related equipment.						Refer to Contract #93039.
Malin-Meridian 500 kV Line Loop Into Captain Jack Substation						
♦ Transmission line modifications. 1/	Pacific	50/50	0/100	Pacific	0/100	3/
Captain Jack Substation						
♦ Bay 3 facilities, including 2-500 kV breakers, 4-MOD's, buswork, PT's, conduit, grounding, towers.	Bonneville	50/50	0/100	Bonneville	0/100	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Property under Bay 3.	Bonneville	50/50	0/100	Bonneville	Prorate	Prorate based on 2/7. BPA to maintain.
♦ Relays and controls, data systems equip. for Bay 3 facilities.	Bonneville	50/50	0/100	Pacific	0/100	PP&L to maintain. BPA retains the right to review any future relay replacements/modifications.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Remaining 5-500 kV breakers, MOD's, buswork towers, conduit, grounding, site develop. 1/	Bonneville	100/0	100/0	Bonneville	100/0	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Station service facilities for the entire station. 1/	Bonneville	100/0	100/0	Bonneville	Prorate	Prorate based on 2/7. BPA to maintain.
♦ Remaining relays and controls, data system equipment. 1/	Bonneville	100/0	100/0	Bonneville	100/0	BPA to maintain.
♦ Control House, exclusive of the property upon which it lies. 1/	Bonneville	100/0	100/0	Bonneville	100/0	Any future expansions due to PP&L additions will be at 100% PP&L costs but BPA to retain 100% ownership.
♦ All remaining property including access road. 1/	Bonneville	100/0	100/0	Bonneville	100/0	Requires identification of boundaries. PP&L has right to add transformer in future.
♦ Series capacitors. 1/	Bonneville	100/0	100/0	Bonneville	100/0	Cost sharing/ownership is with TANC as per Interconnection Agreement (short or long term, whatever prevails). BPA to maintain.
♦ RAS related equipment.						Refer to Contract #93039.
♦ Metering/Telemetering equipment on the Captain Jack-Meridian and Captain Jack-Malin #2 Lines.	Bonneville	50/50	0/100	Bonneville	0/100	BPA to do the maintenance at BPA discretion.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Malin Substation						
♦ Any modifications/additions in PP&L's Control House in support of the Eugene-Medford/Third AC Intertie project, which includes the relay replacement for the Malin-Captain Jack Line. 1/	Pacific	50/50	0/100	Pacific	0/100	BPA retains the right to review any future relay replacements and/or modifications.
♦ Replacement of arresters on PacifiCorp's 500 kV reactor bank No. 4. 1/	Pacific	0/100	0/100	Pacific	0/100	
♦ Replacement of rod gaps with arrestors on PacifiCorp's C.J. Line terminal. 1/	Pacific	50/50	0/100	Pacific	0/100	
♦ RAS related equipment.						Refer to Contract #93039.
♦ Any modifications in main control house.	Bonneville	50/25	50/25	Bonneville	50/25	
♦ Relay replacement for the Summer Lake line.	Pacific	50/50	0/100	Pacific	42/58	Refer to Contract #93644.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Line Relays at Dixonville, Meridian, and Malin and Related Accessories						
♦ Line relays at Dixonville, Meridian, and Malin for the Dixonville-Alvey, Dixonville-Meridian, Meridian-Captain Jack, and Malin-Captain Jack #2 Lines are to be supplied to PP&L at BPA material cost plus BPA overheads. Any additional PP&L overheads, subject to 50/50 cost share, is to be determined.	Pacific	50/50	See Comments			Ownership and O&M of such relays are as described under the respective substations.
♦ Spare Equipment.	Bonneville	50/50	50/50	N/A	N/A	Reference 7/12/91 Letter from Don Feltz to Susan Wiese. Such spare equipment are to be located at PP&L station(s) in Southern Oregon. In addition to that referenced in the 7/12/91 Letter, there may be other spare equipment supplied by PP&L also located in S. Oregon and subject to cost-share. Required test equipment and tools are to be 100% respectively acquired by either BPA or PP&L for 100% discretionary use.
♦ Specialized relay training costs. 1/	N/A	50/50	N/A	N/A	N/A	Cost sharing only if agreed to capitalize such costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
General PSC Modifications						
♦ PSC Modifications at Dittmer and ECC will be 100% BPA and similarly PSC modifications at PP&L control centers will be 100% PP&L.	100% respectively	100% respectively	100% respectively	100% respectively	100% respectively	
♦ Any other modifications at other wholly-owned substations will be 100% of the respective party.	100% respectively	100% respectively	100% respectively	100% respectively	100% respectively	
Summer Lake Substation						
♦ Relay replacement for the Summer Lake-Malin 500 kV Line.	Pacific	50/50	0/100	Pacific	42/58	Refer to agreement #93644.
♦ RAS related equipment.						Refer to Trust Tables 18 & 19, Contract # 37013.
♦ Replacement of rod gaps with arrestors on PacifiCorp's Malin Line terminal. 1/	Bonneville	100/0	0/100	Pacific	0/100	
Sycan Series Compensation Station						
♦ New series capacitor bank in the S. Lake-Malin 500 kV Line.	Bonneville	65/35	65/35	Bonneville	65/35	Refer to agreement #93644.
♦ Bypass switch and associated support structures and foundations.	Bonneville	65/35	0/100	Bonneville	0/100	Refer to agreement #93644.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Dead-End tower.	Pacific	65/35	0/100	Pacific	0/100	Refer to agreement #93644.
Capital Spare Parts						
♦ Various spare parts.		50/50	50/50		42/58	Capital spare parts subject to cost sharing and joint ownership are to be mutually agreed upon and consistent with this agreement.
Overall Planning, Preliminary Engineering, Project Management						
Related costs for the Eugene-Medford Project, including any costs to resolve/mitigate legal matters (e.g., spotted owl and union vs. non-union issues).		50/50	50/50			
Communication:						
♦ Summer Lake-Malin Communication, Two Downlinks. 1/	Pacific	50/50	0/100	Pacific	0/100	Refer to the Sycan Agreement Contract No. DE-MS79-92BP93644 and Cooperative Communications Agreement Contract No. DE-MS79-92BP93740.
♦ Dixonville - Two Microwave Terminals. 1/	Pacific	50/50	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement Contract No. DE-MS79-92BP93740.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Meridian - Two Microwave Terminals 1/	Pacific	50/50	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.
♦ All Other Bonneville Communication Facilities.	Bonneville	100/0	100/0	Bonneville	100/0	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740
♦ Other Pacific Communication Facilities	Pacific	0/100	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.

1/ Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.
2/ Costs of (1) removal of any existing 230 kV facilities; (2) permitting; and (3) incremental right-of-way to be included.
3/ Includes procurement of right-of-way from Meridian-Malin transmission line structures to Captain Jack Substation.

(7664-PMT-W:\CONTRACT\EXH\WP3598EE.DOC)

FACILITIES SERVING PACIFICORP'S LOAD AREA

PacifiCorp's Load Area is the area serviced by the following existing transmission lines and transformers.

1. PacifiCorp's Malin 500-230 kV transformer.
2. PacifiCorp's Yamsey-Chiloquin 230 kV line.
3. PacifiCorp's Dixonville 500-230 kV transformer.
4. PacifiCorp's Alvey-Dixonville 230 kV line.
5. PacifiCorp's Reston-Dixonville 230 kV line.
6. PacifiCorp's Meridian 500-230 kV transformer.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

AUG 16 1991

In reply refer to:
PMTI

Amendment No. 1
Contract No. DE-MS79-86BP92299

Mr. Thomas Lockhart, Vice President
Power Systems
PacifiCorp Electric Operations
920 SW. Sixth Avenue
Portland, OR 97208

Dear Mr. Lockhart:

Pursuant to subsection 4(a) of Contract No. DE-MS79-86BP92299, as amended, (Intertie Agreement) between PacifiCorp Electric Operations (Pacific) and Bonneville Power Administration (Bonneville), Bonneville hereby provides Pacific notice that, effective on the Effective Date, Bonneville is exercising its option to acquire a fifty percent undivided ownership interest in the Alvey-Meridian Line, as defined in such agreement and as modified herein. Pacific and Bonneville hereby agree to amend the Intertie Agreement by supplementing it with the following provisions, and replacing Exhibit C to such agreement with the attached Revision No. 1 to such Exhibit.

1. Completion of the Alvey-Meridian 500 kV Line.

(a) Design and Construction. Pacific and Bonneville shall use best efforts to complete the Alvey-Meridian Line by November 1993. Pacific shall design and construct the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including series capacitors, and the Alvey-Dixonville portion of the Alvey-Meridian Line (Alvey-Dixonville Line) and the Dixonville-Meridian portion of the Alvey-Dixonville Line (Dixonville-Meridian Line). Bonneville shall design and construct the Alvey 500 kV Substation (Alvey Substation) including the Alvey Substation series capacitors. The Parties shall seek opportunities to utilize the capabilities of the other to minimize the installed cost and operation and maintenance cost and maintain schedules. The Parties shall agree at a later date upon the prudent design and construction of the Dixonville-Meridian Line, Dixonville 500 kV Substation series capacitors, and the Meridian Substation series capacitors. Each Party shall have the right to comment on the design and construction to be performed by the other Party.

(b) Maintenance and Operation. Pacific shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including the series capacitors, and the Alvey-Meridian Line. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors. The Parties shall jointly develop maintenance standards and responsibilities that seek to limit the total annual operation and maintenance charges. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Revision No. 1 to Exhibit C.

(c) Ownership.

(1) Pacific and Bonneville shall have undivided joint ownership of the Alvey-Meridian Line based upon the ownership percentages specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(2) Pacific and Bonneville shall have undivided joint ownership of incremental land acquisitions necessary to complete the Alvey-Meridian Line. Pacific shall convey to Bonneville any rights of use of Pacific's existing land sufficient to allow Bonneville to facilitate use of its right to fifty percent of the Incremental Capacity and ownership.

(3) The transfer of property titles (equipment, land, etc.) by the Parties in order to provide for undivided joint ownership shall occur at the time of energization of the Alvey-Meridian Line.

(4) Ownership of the communications systems shall be determined in accordance with section 6.

(d) Expansion of Facilities.

(1) Pacific shall have the right to modify the Dixonville 500 kV Substation and Meridian Substation, at its expense, as necessary for future required facilities without agreement by Bonneville, provided that Bonneville's ownership right to fifty percent of the Incremental Capacity of the Alvey-Meridian Line, as defined in the Intertie Agreement (Incremental Capacity), is not diminished.

(2) Upon expiration of the Intertie Agreement, Bonneville shall have the right to make additional facility connections at the Meridian Substation, at its expense, to facilitate use of its right to fifty percent of the Incremental Capacity, provided that such new connections do not increase loadings on Pacific's exclusively-owned facilities, diminish Pacific's rights to the Alvey-Meridian Line, or adversely impact Pacific's system.

(3) Bonneville shall have the right to modify the Alvey Substation, at its expense, as necessary for future required facilities without agreement by Pacific, provided that Pacific's ownership right to fifty percent of the Incremental Capacity is not diminished.

(4) Upon expiration of the Intertie Agreement, Pacific shall have the right to make additional facility connections at the Alvey Substation, at its expense, to facilitate use of its fifty percent share of the Incremental Capacity, provided that such new facility connections do not increase loadings on Bonneville's exclusively owned facilities, diminish Bonneville's rights to the Alvey-Meridian Line, or adversely impact Bonneville's system.

(e) Cost Sharing/Payment. Cost sharing for design and construction of the Alvey-Meridian Line shall be as specified in Revision No. 1 to Exhibit C. The Parties agree to develop mutually agreeable terms and conditions for payment for design and construction of the line. Such terms and conditions shall include provisions for progress payments, recognition of any payments made by either Party, or expenses incurred by either Party that are associated with the interim agreements (Contract Nos. DE-MS79-90BP92901, DE-MS79-91BP93112, DE-MS79-91BP93112, and DE-MS79-90BP93070) between the Parties as replaced by this amendment.

2. Alvey Substation 500 kV Terminal. Contract No. DE-MS79-90BP92901 shall terminate as of the Effective Date of this amendment.

3. Captain Jack Substation Connection/Terminal.

(a) Contract No. DE-MS79-91BP93112 shall terminate as of the Effective Date of this amendment.

(b) Pacific and Bonneville agree to equally share the cost of the following work performed by Pacific:

(1) procurement of the right-of-way from the Meridian-Malin transmission line structures to Captain Jack Substation;

(2) design and construction of the new 500 kV transmission line from Meridian-Malin 500 kV line structures to the Captain Jack Substation dead end towers;

(3) removal of certain Meridian-Malin 500 kV transmission line facilities; and

(4) design and construction of the strain bus connection between the Captain Jack dead end towers in Bay 3 to connect the Meridian-Malin line segments.

(c) Pacific and Bonneville agree to equally share the cost of the following work performed by Bonneville:

(1) design and construction of Captain Jack Substation dead end structures at Bay 3; and

(2) design and construction of power circuit breakers and associated Bay 3 terminal equipment including relays, and facilities to connect the Meridian-Malin line.

(d) Pacific shall own the land, right-of-way, power circuit breakers, terminal equipment including relays, and facilities up to the dead end towers, the dead end towers, and the strain bus between such towers at Bay 3.

(e) Bonneville shall assume system operation and maintenance responsibilities for all facilities at Captain Jack Substation except terminal Bay 3 relays and communications owned by Pacific, which shall be assumed by Pacific.

4. Sycan.

(a) The following provisions of Contract No. DE-MS79-91BP93157 shall terminate as of the Effective Date of this amendment:

(1) payment provisions specified in Section 4 and Exhibit A;

(2) cost sharing provisions specified in Sections 5 and 6; provided, however, the duties of the Parties described in such Sections shall remain; and

(3) ownership provisions specified in Section 7; provided, however, Pacific shall own the protective relays for the Summer Lake-Malin terminals pursuant to Revision No. 1 to Exhibit C of the Intertie Agreement.

(b) Contract No. DE-MS79-90BP93070 shall terminate as of the Effective Date of this amendment.

(c) Bonneville shall design and construct the series capacitors. Bonneville shall pay the design and construction costs and own the series capacitors until the Parties reach agreement pursuant to subsection 4(f) below.

(d) Bonneville shall operate and maintain the Sycan Compensation Station, including the series capacitors and bypass switch and associated structures; provided, however, the Summer Lake-Malin terminal relays shall be operated and maintained by Pacific. Payment for such operation and maintenance costs shall be as specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(e) The Sycan dead end tower shall be operated and maintained by Pacific.

(f) The Parties shall mutually agree to the terms and conditions for cost sharing for the Sycan series capacitors, bypass switch and

associated structures, Summer Lake-Malin terminal relays, Summer Lake-Malin communications down-link, and dead end tower.

5. Coordinated Operations. The Parties shall jointly develop coordinated operating procedures for the Alvey-Meridian Line, Captain Jack Substation, and Sycan Compensation Station such that Bonneville may adequately perform as the system operator for the combined AC Intertie, and that maximize the Operational Transfer Capability of the AC Intertie and maximize Pacific's capability to serve its southern Oregon and northern California loads pursuant to Section 5(d)(2)(A) of the Intertie Agreement.

6. Communications. The Parties are in substantial agreement as to the terms, conditions, and ownership associated with requirements for communication facilities and equipment described herein, and shall complete such terms and conditions as soon as practicable following execution of this amendment. Such terms and conditions shall be incorporated in a separate agreement.

7. Liability. The Parties agree that if any injunction is issued by a court of competent jurisdiction against either Party's implementation of this amendment, such injunction shall not constitute a basis for a breach of contract action.

8. Effective Date. This amendment shall be effective on the later of:

(a) the issuance of a biological opinion by the United States Fish and Wildlife Service regarding the northern spotted owl which is acceptable to both Parties; or

(b) the date Bonneville receives a copy of this amendment signed by Pacific (Effective Date).

If this amendment is acceptable to Pacific, please sign and return one copy to Bonneville. The remaining copy is for your files. Please have your staff

contact Allen Burns, at (503) 230-3367, to establish a schedule for discussions made necessary by the execution of this amendment.

Sincerely,

Administrator

ACCEPTED:

PACIFICORP ELECTRIC OPERATIONS

By _____
Thomas A. Lockhart

Title Vice President

Date August 16, 1991

Effective Date November 18, 1991

(VS6-PMTI-6802d)

INVESTMENT ALLOCATIONS

Facility	Design	Cost Share % Bonneville/Pacific	Ownership % Bonneville/Pacific	Operation	Maintenance	O&M Payment % Bonneville/Pacific
A. Alvey-Meridian Line:						
• Alvey 500 kV Substation						
– 3 PCB's	Bonneville	50/50	50/50	Bonneville	Bonneville	42/58
• Alvey-Dixonville 500 kV Line 1/	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Dixonville 500 kV Substation						
– Transformer	Pacific	0/100	0/100	Pacific	Pacific	0/100
– 3 PCB's	Pacific	50/50	50/50	Pacific	Pacific	42/58
– 1 180 MVAR Reactor	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Dixonville-Meridian 500 kV Line 1/	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Terminal Facilities for Dixonville-Meridian Line at Meridian 500 kV Sub						
– 2 PCB's	Pacific	50/50	50/50	Pacific	Pacific	42/58
– 1 180 MVAR Reactor	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Series Capacitors						
– Alvey	Bonneville	50/50	50/50	Bonneville	Bonneville	42/58
– Dixonville	Pacific	50/50	50/50	Pacific	Pacific	42/58
– Meridian	Pacific	50/50	50/50	Pacific	Pacific	42/58
B. Captain Jack Substation Bay 3 Terminal Facilities and Loop Line:						
• 500 kV Line Meridian-Malin to Captain Jack Substation 2/	Pacific	50/50	0/100	Pacific	Pacific	0/100
• Bay 3 Dead End Towers	Bonneville	50/50	0/100	Bonneville	Bonneville	0/100
• Power Circuit Breakers and Terminal Equipment Bay 3	Bonneville	50/50	0/100	Bonneville	Bonneville	0/100
• Relays	Bonneville	50/50	0/100	Pacific	Pacific	0/100

INVESTMENT ALLOCATIONS

Facility	Design	Cost Share Bonneville/Pacific	Ownership Bonneville/Pacific	Operation	Maintenance	O&M Payment % Bonneville/Pacific
A. System:						
• Relay Replacement - Summer Lake-Malin Terminals	Pacific	3/	0/100	Pacific	Pacific	42/58
• Series Capacitors	Bonneville	3/	4/	Bonneville	Bonneville	100/0
• Bypass Switch and Associated Support Structures and Foundations	Bonneville	3/	0/100	Bonneville	Bonneville	0/100
• Dead-End Tower	Pacific	3/	0/100	Pacific	Pacific	0/100
B. Communications:						
• Summer Lake-Malin Communication Downlink	Pacific	5/	0/100	Pacific	Pacific	0/100
• All other communications 5/						

1/ Costs of (1) removal of any existing 230 kV facilities; (2) permitting; and (3) incremental right-of-way to be included.
2/ Includes procurement of right-of-way from Meridian-Malin transmission line structures to Captain Jack Substation.
3/ To be determined pursuant to subsection 4(f).
4/ To be determined pursuant to subsection 4(c).
5/ All other communications arrangements to be determined pursuant to section 6.

CALCULATION OF LOSSES

Pursuant to Section 10 of the Letter of Understanding dated May 28, 1993, Bonneville and PacifiCorp have conducted a joint study of electrical losses related to AC Intertie transactions. Representatives of Bonneville and PacifiCorp jointly issued a letter dated April 21, 1994, which stated the conclusions reached as a result of this study. The treatment of electrical losses related to AC Intertie transactions shall be in accordance with the April 21, 1994 letter as summarized below.

Bonneville shall return losses to PacifiCorp. Such return of losses shall be calculated as 0.2 percent (0.2%) of Bonneville's Net AC Intertie Schedule, and shall be scheduled to PacifiCorp 168 hours later. "Bonneville's Net AC Intertie Schedule," means the net of all AC Intertie schedules, other than PacifiCorp's schedules associated with its Northbound and Southbound ownership rights in the AC Intertie. Returned losses shall be scheduled from Bonneville to PacifiCorp's main system points of delivery, or as otherwise agreed by the Parties.

EXAMPLE

On a given hour:

Net AC Intertie Schedule is 4,800 MW

PacifiCorp's Schedule over its AC Intertie capacity is 400 MW

Bonneville's Net AC Intertie Schedule is:

4,800 MW - 400 MW = 4,400 MW

Loss to be scheduled to PacifiCorp 168 hours later:

4,400 MW x 0.2% = 8.8 MW

AUTHENTICATED

Service Agreement No. 98TX-10172

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
TRANSALTA ENERGY MARKETING (U.S.), INC. - TEMUS

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Exhibits	
Exhibit A	(Open Access Transmission Tariff)
Exhibit B	(Application for Point-to-Point Transmission Service)
Exhibit C	(Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit D	(System Impact Study Agreement)
Exhibit E	(Facilities Study Agreement)
Exhibit F	(Wholesale Power and Transmission Rate Schedules)
Exhibit G	(Facilities Charges)
Exhibit H	(Ancillary Services)
Exhibit I	(Transmission Scheduling Provisions)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 26th day of August 1998, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and TransAlta Energy Marketing (U.S.), Inc. – TEMUS (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are

sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

W I T N E S S E T H :

WHEREAS the Parties are interconnected directly or through their Designated Agent(s) with each other and/or with other electric utility systems; and

WHEREAS BPA provides Point-to-Point (PTP) Transmission Service under BPA's Open Access Transmission Tariff (Tariff);

NOW, THEREFORE, in consideration of the promises and mutual covenants and agreements herein contained, the Parties do agree as follows:

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 **Terms and Conditions.** BPA agrees to provide and the Transmission Customer agrees to take and pay for PTP Transmission Services in accordance with the provisions of this Service Agreement and the Tariff. The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference and made a part of this Service Agreement as Exhibit A. BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 **Application.** The Application for PTP Transmission Service requested by the Transmission Customer and accepted by BPA for this Service Agreement is hereby incorporated and made a part of this Service Agreement as Exhibit B.

1.3 **Statement of Specifications for Long-Term Firm Transmission Service.** The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual

transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit C and made applicable to that transaction.

1.4 **System Impact/Facilities Study Agreements.** Study Agreements for a System Impact Study and/or a Facilities Study, if performed for any Application, are hereby incorporated as Exhibits D and E, respectively, and made applicable to those transactions.

1.5 **Wholesale Power and Transmission Rates Schedules.** BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated as Exhibit F.

1.6 **Facilities Charges.** All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit G.

1.7 **Ancillary Services.** The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit H.

1.8 **Transmission Scheduling Provisions.** The Transmission Scheduling Provisions are hereby incorporated as Exhibit I.

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 2400 hours on August 5, 1998. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on

August 4, 2003; or (b) two years after the Transmission Customer provides written notice of termination pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 **Charges for Transmission Service.** The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the rate schedules as specified below.

4.1.1 PTP Transmission Rate (PTP-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.2 Ancillary Products and Services Rate (APS-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.3 Reserved Nonfirm Transmission Rate (RNF-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.4 Energy Transmission Rate (ET-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.5 Advance Funding Rate for facilities listed in Exhibit G (AF-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.6 Use-of-Facilities Rate for facilities listed in Exhibit G (UFT-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.7 Southern Intertie Rate (IS-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.8 Montana Intertie Rate (IM-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.2 **Billing and Payment.** Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and shall be payable in accordance with the Tariff.

4.3 **BPA Appropriations Refinancing Act, Public Law 104-134.** The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Agreement.

ARTICLE 5
NOTICES

5.1 **Notices Relating to Provisions of the Service Agreement.** Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If the notice is to the Transmission Customer:

Attn: Contracts Administrator
TransAlta Energy Marketing (US), Inc. - TEMUS
Box 1900, Station "M"
110-12th Avenue S.W.
Calgary, Alberta
T2P 2M1
Phone: (403) 267-6988
Fax: (403) 267-6907

If the notice is to BPA:

Transmission Account Executive for
TransAlta Energy Marketing (US), Inc. - TEMUS
Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491

5.2 **Notices of an Operating Nature.** Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified transmission service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 **Interconnection with Other Systems.** Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 **Governing Law.** This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3. **Amendments.** Except as provided in Articles 1.1, 6.4 and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 **Tariff Revisions.** In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than 60 days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within 30 days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within 30 days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the transmission service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.5 **Revision of Exhibits.** If any changes to Exhibits C, D, E, F, G, H, or I are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. Except for changes pursuant to Article 6.5.3, the Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.5.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit C pursuant to this Service Agreement, BPA shall prepare a revised Exhibit C. BPA reserves the

unilateral right to amend contiguous point of delivery provisions in Exhibit C of this Service Agreement.

6.5.2 If the Parties execute agreements for a System Impact Study and/or Facilities Study under this Service Agreement, BPA shall prepare a revised Exhibit D and/or Exhibit E.

6.5.3 BPA may change the rates that apply to Transmission Service under this Service Agreement pursuant to applicable law. BPA shall prepare a new Exhibit F.

6.5.4 If the Parties agree to change Exhibit H, BPA shall prepare a new Exhibit H. BPA reserves the right to update the loss factors identified in Exhibit H, section 2, Transmission Loss Factors.

6.5.5 For changes to any of the provisions contained in the Transmission Scheduling Provisions Exhibit (Exhibit I) to reflect current practice, BPA shall prepare a new Exhibit I.

6.6 **Temporary Load Shifts and Maintenance Notification.** The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within 4 days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The

point of contact for each Party will be designated pursuant to Article 5.2 of this Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within 4 days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.7 **Severability.** In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.8 **Computation of Time.** To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.9 **No Third Party Beneficiaries.** This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.10 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in

connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.11 **Successors and Assigns.** This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.12 **Service Agreement Governs.** In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.13 **Designation of Party Subject to Reciprocal Service Obligation.** To the extent that the Transmission Customer or its affiliate owns transmission facilities, the Transmission Customer and its affiliate are subject to reciprocal service obligation.

6.14 **Entire Agreement.** This Service Agreement constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

IN WITNESS WHEREOF, the duly authorized representatives of BPA and the Transmission Customer have executed this Service Agreement as of the date first above written.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ KIPPEN R. MOXNESS

Name: Kippen R. Moxness

Title: Transmission Account Executive

Date: July 31, 1998

TRANSALTA ENERGY MARKETING (US), INC. - TEMUS

By: /S/ ED DE PALEZIEUX

Name: Ed de Palexieux
(Print or Type)

Title: Manager, Real Time Trading

Date: Aug. 26/98

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OPEN ACCESS TRANSMISSION TARIFF

BPA's PTP Tariff shall constitute this Exhibit A until such time as the Commission approves BPA's Open Access Transmission Tariff.

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APPLICATION FOR PTP TRANSMISSION SERVICE

(Not applicable at this time)

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

(Not applicable at this time)

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SYSTEM IMPACT STUDY AGREEMENT

A System Impact Study is not required at this time for the service under this Service Agreement.

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FACILITIES STUDY AGREEMENT

A Facilities Study is not required at this time for the service under this Service Agreement.

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WHOLESALE POWER AND TRANSMISSION RATE SCHEDULES

(Reference the 1996 Wholesale Power and Transmission Rate Schedules or its successor)

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FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

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ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL)	98TX-10172
(b)	**Energy Imbalance**		
(c)	**Control Area Reserves for Resources**		
(d)	**Control Area Reserves for Interruptible Purchases**		
(e)	**Load Regulation**		
(f)	**Reactive Supply and Voltage Control**		
(g)	**Transmission Losses**	BPA(TBL)	98TX-10172

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) Transmission Losses Associated with Federal Power. Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules, are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power. The Transmission Customer shall compensate BPA for losses BPA incurs when providing transmission service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be determined by multiplying the amount of power delivered under this

Service Agreement by the applicable Loss Factor listed below in section 2; and

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) Transmission Losses Associated with Delivery Facilities. Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year 1/, pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

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1/ Fiscal Year is defined as the twelve-month period from October 1 through September 30.

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e.

fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) Notification.

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer shall choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice for compensating BPA for transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit H.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate on the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year:

The Transmission Customer has elected to purchase Transmission Losses, pursuant to the APS-96 rate schedule, at a rate of **22.80** mills per kWh for the period 2400 hours August 5, 1998, through 2400 hours September 30, 1998.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit H as appropriate, but not more frequently than once in a 12-month period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit H incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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TRANSMISSION SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

The purpose of this exhibit is to describe how the Parties will effect transmission transactions under this Service Agreement. The details of requesting and scheduling transmission can be found in the Transmission Scheduling Procedures posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPA

The Transmission Scheduling Procedures may be revised by BPA from time-to-time to reflect changes in business practices.

2. SCHEDULING AGENT DESIGNATION

(a) A single Designated Scheduling Agent (Scheduling Agent) will act in all capacities for the Transmission Customer to access the transmission system. All schedules and schedule changes must be submitted in the name of the Scheduling Agent. This is a yearly designation for the October through September time period.

(b) Any Transmission Customer or its Scheduling Agent using a Host Control Area (HCA), as defined by NERC, other than BPA must establish and verify transmission schedules with other Control Areas through the HCA, but the HCA is responsible for implementing and assuring the accuracy of the transmission schedule.

(c) Any Transmission Customer or its Scheduling Agent must arrange for wheeling across BPA's Control Area with affected parties to/from the agreed upon Points of Interconnection/Delivery consistent with BPA's Scheduling Procedures posted on BPA's OASIS.

3. EXHIBIT PROVISIONS

(a) **Scheduling Principles**

The procedures in this exhibit are intended to achieve the following principles:

(1) promote reliable and efficient system operations; and

(2) provide workable transmission scheduling provisions for the timely delivery of power.

(b) **Control Area Requirements**

(1) In order to schedule transmission for the movement of power, a Transmission Customer must designate an HCA to implement its transmission schedules. Subject to subsection (b)(2) below, the HCA may be the delivering Control Area, the receiving Control Area, or an intermediary Control Area.

(2) BPA shall be the HCA for any transaction involving either:

(A) generation within BPA's Control Area; or

(B) service to a load within BPA's Control Area.

(3) If BPA is the intermediary Control Area in a single transaction or set of transactions, the Transmission Customer may designate an HCA other than BPA. The Transmission Customer must inform BPA of its choice no later than the time of preschedule. BPA has no obligation to accept transmission schedules from any HCA that does not agree to abide by the scheduling requirements set forth in BPA's Transmission Scheduling Procedures posted on BPA's OASIS.

(4) If the Transmission Customer has designated an HCA for a single transmission schedule, the transmission schedule must remain with the HCA for the entire duration of the transmission schedule. In the event the Transmission Customer fails to identify a HCA for its next transmission schedule, BPA will assume that the designated HCA is the same entity as designated for the Transmission Customer's last transmission schedule.

(5) The Transmission Customer may submit interchange transmission schedules; however, the HCA shall confirm and then implement the interchange transmission schedules.

(6) Any Transmission Customer for whom BPA is the HCA must schedule transmission to, from, or within BPA's Control Area.

(c) **Coordinating Requirements**

(1) Scheduled hourly values are to be referenced by the "Hour Ending" time on the 24-hour clock (i.e., the schedule for 2-3 p.m. is referred as the "hour ending 15" or in other words "hour ending 1500").

(2) Unless otherwise agreed, all transmission schedules will be effectuated on an hourly basis using the standard 20-minute ramp period centered on the hour (i.e., beginning 10 minutes prior to the hour and ending 10 minutes after the hour).

(3) All schedules with BPA are to be stated in Pacific Time (PT) and are to begin with the Hour Ending 1.

(4) The Transmission Customer or its Scheduling Agent agrees to submit all hourly scheduled quantities in whole megawatthour amounts.

(d) **Prescheduling Requirements**
Prescheduling is the process of establishing hourly schedules.

(1) **Preschedule Submissions**

(A) The Transmission Customer or its Scheduling Agent agrees to submit Transmission Schedule(s) covering all transactions into, out of, or within BPA's Control Area.

(B) BPA may require the Transmission Customer or the Transmission Customer's Scheduling Agent to submit *estimated* preschedules prior to the final preschedule.

(C) The Transmission Customer or its Scheduling Agent agrees to submit a *final* hour*ly* preschedule for the next day or days consistent with the BPA's Transmission Scheduling Procedures as posted on BPA's OASIS.

(2) **Information Required to Be Included in Preschedule**
Any schedule submitted to BPA by the Transmission Customer or its Scheduling Agent must include, at a minimum, the following information:

(A) the HCA;

(B) the supplier (delivering party), receiver (Receiving Party), and wheeling entities involved in the transaction;

(C) the hourly MW amount of the transmission schedule;

(D) the starting and ending times for each transmission schedule;

(E) the Transmission Service being scheduled by product type (i.e. PTP or NT and firm or nonfirm) and subproduct type (i.e. hourly, daily, weekly, monthly, and/or annual);

(F) the Point of Interconnection/Delivery for the transaction;

(G) Transmission Agreement Contract Numbers and/or OASIS Reservation identification numbers as required by NERC; and

(H) all other pertinent information as required for transmission scheduling listed in BPA Transmission Scheduling Procedures posted on BPA's OASIS.

(e) **Real Time Changes**

(1) To the extent changes from the preschedule become necessary, the Transmission Customer or its Scheduling Agent must submit such requests to change the transmission schedule as specified in BPA's Transmission Scheduling Procedures posted on BPA's OASIS.

(2) Multihour changes from preschedule shall specify an "Hour Beginning" and an "Hour Ending" and shall never be stated as "until further notice."

(3) Upon a Transmission Customer's or its Scheduling Agent's request, BPA will consider mid-hour changes from preschedule under critical operating conditions such as loss of a resource or transmission path. The Transmission Customer or its Scheduling Agent and BPA must agree to the effective time, ramp duration, integrated, and revised net schedules for mid-hour changes. Mid-hour schedule changes shall not be made for economic or load shaping purposes. Such changes are subject to applicable charges.

(f) **Emergency Requirements**

(1) **Loss of Transmission Path**

(A) The path operator shall notify affected Transmission Customers, their Scheduling Agents and HCAs as rapidly as possible of the loss of a transmission path.

(B) The path operator will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify transmission schedules, as required, per the established effective time, and agree on integrated and revised net transmission schedules.

(2) **Loss of Generating Resource**
The Transmission Customer agrees to adhere to the following requirements for any resources that it operates, and agrees to ensure, through contractual arrangement, that any entity operating a resource on its behalf likewise agrees to the following:

(A) The operating entity (generating entity) will notify BPA and affected Transmission Customers, their Scheduling Agents, and HCAs as quickly as possible of the resource loss.

(B) The entity with Control Area responsibility will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify transmission schedules, as required, as of the established effective time, and agree on integrated and revised net schedules.

(3) **General Provisions Regarding Emergencies**
BPA and the Transmission Customer, its Scheduling Agent, and HCA agree to expedite communications to avoid accumulation of inadvertent powerflows or net transmission schedules which place a control burden on other Control Areas.

(g) **After-the-Fact Verification**

The Transmission Customer or its Scheduling Agent agrees to verify all transmission schedules and tie checks each week with a final verification at the end of each month consistent with the following principles:

(1) The Transmission Customer or its Scheduling Agent and BPA will check all scheduled transmission.

(2) The Transmission Customer or its Scheduling Agent and BPA will agree on the hourly transmission amounts and the transmission attributes of the transmission schedule (i.e. firm, nonfirm, hourly, daily, weekly, monthly, annual), transmission loss calculations, and transmission loss schedules (as appropriate).

(3) The Transmission Customer or its Scheduling Agent will assist BPA, as necessary, to reconcile all differences between actual and scheduled deliveries in a timely manner.

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 12

The OASIS Number is 756-P, the Assignment Reference Number (ARef) is: 1350339

1. TERM OF TRANSACTION

Start Date: 0000 hours on July 1, 2006.
Termination Date: 0000 hours on July 1, 2007.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1]	POR (Voltage)	POR Control Area	Maximum POR Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]	Scheduling Agent[2]
	John Day (500 kV)	BPA	See Sect. 3 Below	California Oregon Border (500 kV)	CAISO	See Sect. 3 Below		TransAlta Designated Agent
Total Transmission Demand			**See Sect. 3 Below**			**See Sect. 3 Below**		

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and/or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF RECEIPT AND POINTS OF DELIVERY

Point(s) of Receipt (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	**COB (500 kV)**	**(42 MW)**	**IS-04**

4. DESCRIPTION OF POINTS OF RECEIPT

John Day Substation

Location: the points in BPA's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

California Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB), where BPA shall make electric power available for the California Independent System Operator (CAISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $49,392, shall be paid to the Transmission Provider. For the second reservation fee, the Transmission Provider will bill the Transmission Customer 30 days prior to their due date. If the deferral or extension of the service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The reservation fee is based on the IS rate only and does not include either of the two Ancillary Services that the Transmission Customer is obligated to purchase from the Transmission Provider.

TRANSALTA ENERGY MARKETING (US), INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ TOM COYLE**	By: **/S/ BRIAN D ALTMAN**
Name: **Tom Coyle** *(Print/Type)*	Name: Brian D. Altman *(Print/Type)*
Title: **President**	Title: Transmission Account Executive
Date: **18 Oct/04**	Date: **4 Oct 04**

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Amendment No. 1
Contract No. 98TX-10172

AUTHENTICATED

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

TRANSALTA ENERGY MARKETING (US), INC. - TEMUS

This AMENDMENT to the Transmission Service Agreement, Contract Number 98TX-10172, (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and TransAlta Energy Marketing (US) (herein after referred to as "the Transmission Customer") The Transmission Customer and BPA are sometimes referred to individually as "Party", and collectively as "Parties" as the context suggests below.

This Amendment No. 1 (Amendment) to the Agreement between BPA and the Transmission Customer acknowledges the Parties' desire to extend the term of the Agreement to 2400 hours September 30, 2010. The Parties agree that all other terms and conditions of the Agreement remain the same. Article 3 of the Agreement is hereby amended to read as follows:

> "Service under this Service Agreement shall commence at 2400 hours on August 5, 1998. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on September 30, 2010; or (b) two years after the Transmission Customer provides written notice of termination pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied."

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

TRANSALTA ENERGY MARKETING (US), INC. - TEMUS

By /s/ DENISE E. HILL

Name DENISE E. HILL
(Print/Type)

Title MANAGER, PORTLAND OPERATIONS

Date JANUARY 20, 2000

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ KIPPEN R. MOXNESS
Transmission Account Executive

Name Kippen R. Moxness
(Print/Type)

Date JANUARY 19, 2000

(TM-TMC-W:\TMC\CT\TransAlta\10172AA!)

AUTHENTICATED

Exhibit C Table 5
STATEMENT OF SPECIFICATIONS FOR
LONG-TERM FIRM TRANSMISSION SERVICE

1. TERM OF TRANSACTION

Start Date: at hour ending 0100 hours on October 1, 2003.

Termination Date: at 2400 hours on September 30, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LADWP	See Sect. 3 Below		TransAlta Designated Agent
Total Transmiss Demand			See Sect. 3 Below			See Sect. 3 Below		

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation 230/500 kV	NOB 1000 kV	10/01/03 - 9/30/06: 100 MW	IS-96

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation:

Location: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses.

Voltage: 230/500 kV

Metering: quantities are to be scheduled

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

5. **POINTS OF DELIVERY**

Nevada/Oregon Border (NOB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer.

Voltage: 1,000 kV

Metering: quantities are to be scheduled

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and it's affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
none

8. **RESERVATION FEE:** Within thirty (30) days after the Transmission Customer signs this Exhibit A Table 5 to the Service Agreement, the first annual nonrefundable reservation fee of $ 127,400.00 shall be paid to BPA. For the second and subsequent reservation fees, BPA will bill the Transmission Customer thirty (30) days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS Rate only and does not include Ancillary Services.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ KIPPEN R. MOXNESS

Name: Kippen R. Moxness

Title: Transmission Account Executive

Date: January 30, 2001

TRANSALTA ENERGY MARKETING (US)

By: /S/ DENISE HILL

Name: 2/20/01 Denise Hill
(Print/Type)

Title: Mgr, Transmission

Date: 2/20/01

(W\TMC\CT\10172CT5.DOC) 01/29/01

Contract No. DE-MS79-89BP92273
12/05/89

GENERAL TRANSMISSION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

[Integration of Resources]

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This GENERAL TRANSMISSION AGREEMENT, executed December 11, 1989, by the UNITED STATES OF AMERICA (Government), Department of Energy (DOE), acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PORTLAND GENERAL ELECTRIC COMPANY (Company), a corporation of the State of Oregon,

W I T N E S S E T H :

WHEREAS Bonneville and the Company, on August 27, 1982, entered into Contract No. DE-MS79-81BP90425, (which as the same may be amended or replaced is hereinafter referred to as Power Sales Contract); and

WHEREAS Bonneville and the Company have entered into the following transmission agreements: Contract No. 14-03-001-13437 for the Priest Rapids Project; Contract No. 14-03-001-13773 for the Rocky Reach Project; Contract No. 14-03-28002 for the Wanapum Project; Contract No. 14-03-29139 for the Centralia Thermal Project; Contract No. 14-03-41848 for the Wells Project; Contract No. 81BP90167 for the Colstrip Project; and Contract No. DE-MS79-81BP90016 for the Beaver Project (which are hereinafter collectively referred to as the Prior Agreements); and

WHEREAS Bonneville and the Company desire to replace the Prior Agreements with this general transmission agreement; and

WHEREAS Bonneville and the Company have negotiated this agreement, the General Transfer Agreement, Contract No. DE-MS79-89BP92384, and a Letter Agreement, Contract No. DE-MS79-90BP92865, contemporaneously such that the Bonneville and the Company benefit from favorable terms in one agreement in exchange for concessions in the others; and

WHEREAS Bonneville and the Company are owners of certain AC Intertie facilities and have agreed to share the transmission capacity of the combined facilities through the terms and provisions of Contract No. DE-MS79-87BP92340 (Intertie Agreement); and

WHEREAS the Company has rights to transmission over the Montana Intertie pursuant to Contract No. DE-MS79-81BP90210 (Montana Intertie Agreement); and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Term of Agreement.

(a) This agreement shall be effective at 2400 hours on December 31, 1989 (Effective Date) subject to subsection 9(e) and shall continue in effect until 2400 hours on December 31, 2009.

(b) Upon expiration of this agreement, Bonneville will offer to extend transmission services provided hereunder, of the same quality as, and on terms and conditions consistent with, those being offered at that time to other customers similarly situated.

(c) If the Total Transmission Demand is reduced to zero pursuant to the terms and provisions of subsection 10(b), the Company may request termination of this agreement subject to satisfaction of all obligations accrued hereunder and completion of all notice periods specified in subsection 10(b) for the resources involved.

2. Termination of Prior Agreements. The Prior Agreements are hereby terminated as of the Effective Date hereof, but all obligations incurred thereunder are hereby preserved until satisfied.

3. Definition and Explanation of Terms.

(a) "AC Intertie." The alternating current (AC) transmission facilities, located in the State of Oregon, for transferring power and energy between the

Pacific Northwest and California, consisting of two 500 kV AC lines from John Day Substation to the California border and associated facilities.

(b) "Agency." The Agency authorized to approve Bonneville's transmission rates.

(c) "Electric Power" or "Power." Electric peaking capacity, expressed in kilowatts, or electric energy, expressed in kilowatthours, or both.

(d) "FCRTS" or "Federal Columbia River Transmission System." The transmission facilities of the Federal Columbia River Power System (FCRPS), which include all transmission facilities owned by the Government and operated by Bonneville, and other regional facilities over which Bonneville has obtained transmission rights.

(e) "Points of Delivery" or "POD." The point or points, named in the Transmission Parameters Exhibit, where Electric Power may be made available to the Company hereunder.

(f) "Points of Integration" or "POI."

(1) The point or points listed in the Transmission Parameters Exhibit, where Electric Power from the Company's Resources shall be integrated into the FCRTS hereunder; or

(2) the point or points mutually agreed upon by the parties hereto where Electric Power from other Resources may be made available to Bonneville for nonfirm transmission to the Company's Points of Delivery.
If requested, the Resources to be integrated at each Point of Integration shall be identified.

(g) "Resource."

(1) Any of the Company's generating or contractual resources listed in the Transmission Parameters Exhibit requiring firm transmission services on the FCRTS; and

(2) any resource within the Pacific Northwest region as defined in the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act) Section 3 (14), that is acquired from regional utilities for which nonfirm transmission service is requested and which is made available to Bonneville at mutually agreed upon Points of Integration on the FCRTS; and

(3) any resource within the Pacific Northwest region as defined in (2) above supplying backup power or station service to the Company's other resources, which requires nonfirm transmission and which is made available to Bonneville at the Company's Points of Integration on the FCRTS.

(h) "Southern Intertie." The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border, a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation, and one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

(i) "Southern Intertie Terminals." The John Day and Big Eddy Substation facilities which terminate the lines for transferring power and energy between the Pacific Northwest and the Pacific Southwest.

(j) "Total Power Integrated." For each hour, it is the sum of both firm and nonfirm Electric Power scheduled hereunder on such hour to Bonneville at all points on the FCRTS where Bonneville accepts such Electric Power from the Company for transmission hereunder to the Company's Points of Delivery.

(k) "Transmission Demand." The maximum firm transmission capacity which Bonneville shall be obligated to have available at each Point of Integration for the purpose of integrating Electric Power from a Resource specified in the Transmission Parameters Exhibit for the Company hereunder. The level of the Transmission Demand shall be based on the hourly peak capability of the

Company's Resource to be integrated hereunder at such Point of Integration. The sum of the Company's Transmission Demands (Total Transmission Demand) is specified in the Transmission Parameters Exhibit.

(l) "Use-of-Facilities Charge." The charges, if any, specified in the Transmission Parameters Exhibit, applicable to Points of Integration and Points of Delivery for the purpose of recovering the cost of identifiable facilities provided by Bonneville for the Company's use, provided payment for such use is not otherwise included in the charges pursuant to subsection 6(a).

(m) "Workday." For the purpose of power scheduling, it is a day which the parties hereto jointly observe as a regular workday.

4. Exhibits; Interpretations. The rights and obligations of the parties with respect to provisions hereunder shall be subject to and governed by this agreement, including Exhibits A through E (Exhibits) attached hereto and by this reference made a part of this agreement. The provisions of Section 38 of the General Wheeling Provisions [GWP Form-4R] require a minimum notification prior to a Rate Adjustment Date. If the rates are disapproved or conditions are placed on them by the Agency, Bonneville shall not be required to give minimum notice prior to resubmitting the rates to the Agency or implementing Agency approved rates. The headings used in this agreement are for convenient reference only, and shall not affect the interpretation of this agreement. The Company shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in the General Wheeling Provisions Exhibit.

5. Integration of Electric Power.

(a) During each hour of the term hereof, subject to the conditions stated herein, the Company shall make available or arrange to have made available to Bonneville, at the Points of Integration, the Total Power Integrated; and Bonneville shall, for each such hour, make an amount of Electric Power equal

to the Total Power Integrated available to the Company at the Points of Delivery, subject to the conditions in paragraphs (a)(1) through (a)(3) below.

(1) Bonneville may, but shall not be obligated to, integrate amounts of Electric Power on any hour which exceed the Total Transmission Demand.

(2) Bonneville may, but shall not be obligated to, integrate at a Point of Integration on any hour, amounts of Electric Power which exceed the Transmission Demand at such Point of Integration.

(3) Bonneville may, but shall not be obligated to, integrate Electric Power from Resources other than Resources listed in the Company's Transmission Parameters Exhibit, provided that the Points of Integration for such Electric Power have been mutually agreed upon; provided however any such integration of power, to the extent that the Total Transmission Demand is not exceeded, shall be provided in accordance with the Integration of Resources Transmission Rate Schedule; and provided further that Bonneville agrees not to refuse to provide and not to interrupt nonfirm transmission under this agreement for the delivery of the Company's purchases from Resources for displacement of its Resources solely for Bonneville to market electric energy to the Company. The Energy Transmission Rate Schedule shall not be applicable to integration of power from Resources to the extent such integration does not exceed the Total Transmission Demand.

(b) As between Bonneville and the Company, sharing the capability to deliver power and energy over the Southern Intertie is defined and limited by the terms and conditions of the Intertie Agreement. Nothing in this agreement, including integration by Bonneville of power and energy at Points of Delivery at the Southern Intertie Terminals, is intended to provide rights to use the Southern Intertie or to expand the rights defined in the Intertie

Agreement. Bonneville shall also accept or deliver Electric Power for delivery over the Montana Intertie as provided by the Montana Intertie Agreement. Nothing in this agreement shall provide for rights to use the Montana Intertie or expand the rights defined in the Montana Intertie Agreement.

(c) If, for any hour, the Company determines that it has Electric Power available for nonfirm transmission over the FCRTS, which would cause the Total Power Integrated to temporarily exceed the Total Transmission Demand, the Company may request nonfirm transmission service from Bonneville and Bonneville may provide transmission service for such excess Electric Power as a separately identified part of its schedule pursuant to Section 7. Charges for such transmission shall be applied in accordance with the Energy Transmission rate schedule, or its successor, attached hereto as part of Exhibit A.

(1) The option to schedule Electric Power as nonfirm transmission service shall not be used to avoid having a Total Transmission Demand which reasonably reflects Transmission Demand for each Resource and the noncoincidental sum of the peak demand for integrating firm energy which the Company places on Bonneville's system. Bonneville shall have the right to refuse to provide service on a nonfirm basis if it determines that the Transmission Demand at a Point of Integration should be increased or the Total Transmission Demand should be increased; provided that this sentence shall not apply if the Company has requested an increase in Transmission Demand, and Bonneville is unable to accommodate this request.

(2) Any transaction using the FCRTS which is exempt from transmission charges or loss assessment at the time of actual transmission, such as qualifying transactions under the Coordination Agreement (Contract No. 14-03-48221), and which is subsequently converted

to a sale to an entity other than Bonneville, shall be retroactively billed as nonfirm transmission service and shall be assessed losses unless such conversion is allowed or provided for under another agreement to which Bonneville is a party. Such qualifying transactions shall not be subject to paragraph (c)(1) above and (d) below.

(d) Except as provided in subsection 5(c) for nonfirm transmission, amounts of Electric Power integrated hereunder which exceed the Transmission Demand shall be billed under the ratchet provision of Section 6, or the Bonneville rate for transmission without prior agreement, should such a rate be developed and approved by the Agency in the future.

(e) To compensate Bonneville for losses incurred in providing services hereunder, the Company shall make available to Bonneville from the Company's system Points of Delivery unless otherwise mutually agreed between the parties, at the corresponding hour 168 hours later or at another hour mutually agreed upon, the amounts of Electric Power determined pursuant to the Calculation of Losses Exhibit (Returned Losses) for service performed pursuant to subsections (a) and (c) above.

(f) Bonneville shall, if requested by the Company and if it is within Bonneville's capability to do so without adversely affecting its other obligations, make replacement Electric Power available to the Company hereunder, without additional cost to the Company except as provided in this subsection, if Electric Power to be made available to Bonneville pursuant to subsection (a) above cannot be made available solely because of suspension or interruption of, or interference with, the operation of the FCRTS. The Company shall, at Bonneville's option:

(1) reimburse Bonneville for any cost or loss of revenue incurred in making such replacement Electric Power available;

(2) replace all or a portion of such replacement Electric Power with the Company's Electric Power at a time agreed upon by the parties prior to delivery; or

(3) reimburse and replace pursuant to paragraphs (1) and (2) above in amounts determined by Bonneville which in total are equivalent in value to the replacement Electric Power delivered to the Company pursuant to this subsection. The method to replace or reimburse shall be specified by Bonneville at the time of the Company's request for replacement Electric Power.

(g) The Company shall not use rights obtained under this agreement to provide transmission services for another entity.

6. Payment by the Company. As compensation for services provided hereunder, the Company shall pay Bonneville each month during the term hereof, amounts determined as provided in this Section and in accordance with the Transmission Parameters Exhibit and the Transmission Rate Schedules and General Transmission Rate Schedule Provisions Exhibit. Any ratchet demand that may occur as determined by Bonneville pursuant to the Transmission Rate Schedules and General Transmission Rate Schedule Provisions, does not constitute an increase in any Transmission Demand approved by Bonneville and any continued service at such level will depend on the availability of facilities as determined by Bonneville. Any changes in Transmission Demands must be requested in accordance with Section 10.

(a) For integration of Electric Power up to the Total Transmission Demand pursuant to subsection 5(a), the Company shall pay Bonneville in accordance with the IR rate schedule, or its successor rate, and in accordance with the Use-of-Facilities methodology in Exhibit C.

(b) For nonfirm transmission of Electric Power pursuant to subsection 5(c), the Company shall pay Bonneville in accordance with the Energy Transmission Rate Schedule, or its successor.

7. Power Scheduling. The Company shall submit or arrange to have submitted the schedule for the Total Power Integrated to Bonneville by 1200 hours (Pacific Time) of each Workday:

(a) for resources requiring transmission herein to which the Company has generation control:

(1) a retroactive report of the Electric Power supplied to Bonneville for each hour of the previous day or days: and

(2) at Bonneville's request, estimated amounts of Electric Power as specified in paragraph (1) above for each hour of the following day or days;

(b) for resources requiring transmission herein to which the Company does not have generation control:

(1) at Bonneville's request, a schedule in advance of Electric Power to be supplied to Bonneville for each hour of the following day or days; and

(2) if the resource is within Bonneville's control area, a retroactive report of the Electric Power supplied by each resource as made available to Bonneville for each hour of the previous day or days.

(c) A retroactive report of the hourly amounts of Electric Power which the Company made available to Bonneville for nonfirm transmission pursuant to subsection 5(c); provided however, that if requested by Bonneville, the Company shall submit estimated amounts of Electric Power to be made available for nonfirm transmission and indicate the Point of Integration where such Electric Power shall be made available; and

(d) separate schedules of the hourly amounts of Electric Power to be made available pursuant to subsection 5(e) for losses for each hour of the following day or days.

8. Reactive Power. It is the intent of the parties hereto that the voltage levels at the Points of Integration and the Points of Delivery be controlled in accordance with prudent utility operating practice. The parties hereto shall jointly plan and operate their systems so as not to place an undue burden on the other party to supply or absorb reactive power accompanying or resulting from interconnections of the systems of the parties and from the integration of Electric Power or deliveries hereunder.

9. Revision of Exhibits.

(a) The rate schedules included in the Transmission Rate Schedules and General Transmission Rate Schedule Provisions Exhibit shall be replaced by successor rate schedules in accordance with the provisions of subsection 7(i) of the Pacific Northwest Power Act and Agency rules. The unit rate or rates in such successor rate schedules shall be a non-mileage based rate which shall only reflect the distances between POI's and POD's if a short distance discount factor has been agreed upon by the parties.

(b) The initial rate schedules to be attached in the Transmission Rate Schedules and General Transmission Rate Schedule Provisions Exhibit have been confirmed and approved by the Agency on an interim basis. If the final rate schedules which are approved by the Agency are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated general transmission rate schedule provisions shall be attached hereto and made a part of this agreement effective as of the date specified in the Agency's approval.

(c) Bonneville shall annually review the Calculation of Losses Exhibit and shall revise such exhibit as appropriate to incorporate values which represent then current FCRTS operating conditions or to incorporate any value, used in such exhibit to calculate the losses, which has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with the Company. Bonneville shall prepare a new Losses Exhibit incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that other Use-of-Facilities Charges specified herein or Parameters used in calculating any charges specified in this agreement must be changed pursuant to Sections 19 or 38 of the General Wheeling Provisions Exhibit, it shall prepare a new Transmission Parameters Exhibit or other affected exhibit incorporating such revised charges and factors. Such new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. Use-of-Facilities Charges may be increased to accommodate the addition of new facilities associated with Points of Integration and Delivery only if such facilities are reasonably necessary to continue providing service, pursuant to this agreement, of the same quality as that provided at the beginning of the term hereof or as of the effective date of additional Points of Integration and Delivery, as appropriate.

(e) Part C of the Transmission Parameters Exhibit (Exhibit C) contains the methodologies for calculating the Joint Use-of-Facilities Charges and the Sole Use-of-Facilities Charges. Bonneville agrees, for the term of this agreement, to seek continuance of such methodology by advocating a rate schedule or schedules which accommodate the methodology set forth in Part C to the Agency or its successor, or a court of competent jurisdiction, and, except

as provided below, to never propose a change in such methodology, applicable to this agreement, in any rate procedure conducted under Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 USC Section 839e(i). In the event Bonneville is required by the Agency or a court of competent jurisdiction, to change such methodology, the Company and Bonneville may agree upon another mutually acceptable methodology and seek appropriate regulatory approval, if necessary. If Bonneville and the Company fail to agree on a methodology, or if regulatory approval is not granted, then the Company shall have the right to terminate this agreement upon notice of not less than 1 year and not more than 5 years, provided however, that upon termination Bonneville shall offer to extend resources integration transmission services including services to the Southern Intertie Terminals, of the same quality as, and on terms and conditions consistent with those being offered at that time to other customers similarly situated.

10. Addition or Deletion of Points of Integration and Points of Delivery and Changes in Transmission Demands.

(a) Points of Integration and Points of Delivery may be added and Transmission Demands may be increased, subject to mutual agreement of the parties and to Bonneville's determination of available transmission capacity, upon 3 months' prior written notice to Bonneville, but no more frequently than once in any 12-month period for any individual point or Transmission Demand. Such changes shall be effective for the remaining term of this agreement unless otherwise indicated in the appropriate exhibits hereto, or changed pursuant to the provisions hereof.

(b) Points of Integration and Points of Delivery may be deleted and Transmission Demands may be reduced subject to the provisions of paragraphs (b)(1) through (b)(5) below.

(1) Transmission Demands for individual Points of Integration may be reduced no more frequently than once in any 12-month period for any Point of Integration, subject to the provisions of paragraph (b)(4) below and the notice requirements of paragraph (b)(5) below and only:

(A) to the extent that, pursuant to the provisions of agreements between the Company and the owner of a Resource designated in the Transmission Parameters Exhibit as being integrated at such Point of Integration, the Resource owner withdraws all or a portion of the Company's share of the Resource output; or

(B) to the extent that the Company assigns all or a portion of its share of the Resource output; or

(C) to the extent of a permanent partial or total reduction in the Company's entitlement to a share of the capability of the Resource; or

(D) to the extent of the destruction, abandonment, or sale of a Resource integrated at such Point of Integration; or

(E) to the extent of the discontinuation of operation of a Resource under a final order of a public official having authority to issue such order.

(2) A Point of Integration may be deleted, upon 3 months' prior written notice to Bonneville, subject to paragraph (b)(4) below, but only after its Transmission Demand has been reduced to zero pursuant to paragraph (b)(1) above.

(3) A Point of Delivery may be deleted, subject to mutual agreement of the parties hereto and to paragraph (b)(4) below, upon 3 months' prior written notice to Bonneville.

(4) A reduction of a Transmission Demand or the deletion of a Point of Integration or a Point of Delivery shall not decrease the Company's obligation to pay, for the duration of this agreement, the Use-of-Facility Charges specified in the Transmission Parameters Exhibit, except to the extent that another customer of Bonneville obligates itself to make such payments to Bonneville for the remainder of the duration of this agreement; provided, however, that upon mutual agreement, the parties may negotiate a termination charge in lieu of continued periodic payment of Use-of-Facility Charges for the duration of this agreement.

(5) The Company shall provide Bonneville 3 years' written notice of any decrease in Transmission Demand, except as follows:

(A) the Company shall provide 3 months' written notice of a decrease in Transmission Demand if there is an equal increase in Transmission Demand by another customer at the same Point of Integration resulting from the sale or assignment of the Resource and involving no loss of revenue to Bonneville; or

(B) the Company shall provide written notice as soon as possible if such decrease is due to involuntary total or partial loss of a Resource, or discontinuation of operation of a Resource under a final order of a public official having authority to issue such order, or if the Company's right to receive Electric Power is reduced or eliminated according to the terms of an agreement between the Company and another entity for such Electric Power.

(c) When changes are made pursuant to this Section, Bonneville shall incorporate such changes in a new Transmission Parameters Exhibit as soon as practicable.

11. Ratification of Interim Agreement. Bonneville billed and the Company paid for transmission services for the Boardman Project pursuant to the FPT Transmission Rate Schedule for the following periods: From 2400 hours August 3, 1980 to 2400 hours June 27, 1982; and from 2400 hours January 31, 1984 to 2400 hours August 18, 1984.

Bonneville billed and the Company paid for transmission services for the Boardman Project pursuant to the IR Transmission Rate Schedule for the following periods; from 2400 hours on June 27, 1982 to 2400 hours on

January 31, 1984; and from 2400 hours on August 18, 1984 to the Effective Date of this agreement.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Walter E. Pollard
Assistant Administrator
for Power Sales

James J. Jura

PORTLAND GENERAL ELECTRIC COMPANY

By E. Kay Stepp

Title President

Date December 11, 1989

(VS6-PMT-3188e)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Transmission Parameters

A. Points of Integration, Transmission Demands, and Resources.

Point of Integration (Voltage)	Transmission Demand	Resource(s) to be Integrated
Midway Substation (230 kV)	131 MW	Priest Rapids Development 1/
Rocky Reach Switching Station (230 kV)	143 MW	Rocky Reach Project 1/
Vantage Substation (230 kV)	161 MW	Wanapum Development 1/
Douglas Switch Yard (230 kV)	169 MW	Wells Project 1/
Garrison Substation (500 kV)	270 MW	Colstrip Project 2/
C.W. Paul Substation (500 kV)	34 MW	Centralia Thermal Project
Allston Substation 3/ (230 kV)	531 MW	Beaver Combined Cycle Plant
Slatt Substation (500 kV)	349 MW 4/	Boardman Project
Total Transmission Demand	1788 MW	

1/ BPA will integrate from these POI's to the POD's listed in this exhibit Electric Power the Company obtains from other participants' shares of these Resources up to the Company's full Transmission Demand at each of these POI's.

2/ BPA will integrate from the Garrison POI to the POD's listed in this exhibit additional Electric Power belonging to the Company other than the Company's shares of the Colstrip Project which the Company makes available to Bonneville at the POI; provided, however, (i) the total Power made available at the Garrison POI shall not exceed the Transmission Demand for that POI; and (ii) the resource is a resource within the Pacific Northwest region as defined in the Pacific Northwest Electric Power Planning Conservation Act (Pacific Northwest Act) Section 3(14), and was in operation on May 17, 1988, or is from shares of Colstrip 1, 2, 3, and 4 other than the Company's shares. This provision does not increase nor decrease any rights that the Company has pursuant to Contract No. DE-MS79-81BP90210 (Montana Intertie Agreement), nor does this contract take precedence over other firm transmission contracts between Bonneville and other utilities.

3/ Beaver Combined Cycle Project (Beaver) integration involves a short distance discount. The POD's served by Beaver are all within 75 circuit miles of Beaver. The demand portion of the transmission charge for Beaver pursuant to the IR Rate Schedule Short Distance Discount is determined from following formula:
(.2 + [(.8/75) x distance]) (IR Rate per kW of transmission demand) =
Monthly charge per kW transmission demand
Applying power flow J8801CY87 dated 7/22/87, which is based on the normal operating situation with Trojan operating and Beaver idle, the Short Distance Discount is as follows:

POD	Demand (MW)	(Circuit Miles)	Factor	Charge $/kW	Compensation Charge $/kW
Keeler	270.0	42.4	0.652	0.170	0.086
Rivergate	150.0	50.7	0.743	0.193	0.055
Pearl	111.0	60.7	0.847	0.220	0.046
Total Demand	531.0				0.187/kW

4/ The Company's share of the Boardman Project totals 424 MW. The Company entered into a Long Term Power Sales Agreement with San Diego Gas & Electric Company (SDG&E) for 75 MW of the Company's share of the Boardman Project. Transmission services for this transaction are covered under Contract No. DE-MS79-86BP92260 which expires at 2400 hours on December 31, 2013. BPA will integrate from this POI to the POD's listed in this exhibit, Electric Power the Company obtains from other participants' shares of the Resource up to the Company's full Transmission Demand at the POI.

B. Points of Delivery and Use-of-Facilities Charges.

Points of Delivery	Use-of-Facilities Charges 1/
Bethel Substation (230 kV)	0
Big Eddy Substation (230 kV) 2/ (Southern Intertie)	0
D. R. Keeler Substation (230 kV)	0
John Day Substation (500 kV) 2/ (Southern Intertie)	0
McLoughlin Substation (230 kV)	0
Pearl Substation (230 kV)	0
Rivergate Substation (230 kV)	0
Trojan Substation (230 kV) 3/	0
Points of Delivery for Station Service Only Unless Otherwise Noted 4/	
Rocky Reach Switching Station (230 kV)	0
Midway Substation (230 kV)	0
Vantage Substation (230 kV)	0
C.W. Paul Substation (500 kV)	0
Allston Substation (230 kV)	0
Slatt Substation (500 kV) 5/	6/
Garrison Substation (500 kV)	0

1/ There are no charges as of the Effective Date of this exhibit. Any revisions to these original zero charges shall be in accordance with subsection 9(d).

2/ Transmission of Electric Power over the Southern Intertie shall be in accordance with the terms and conditions of the Intertie Agreement, Contract No. DE-MS79-87BP92340. If Bonneville establishes other AC Intertie Points of Delivery and upon the Company's request, Bonneville may add them here according to Company's rights under the Intertie Agreement.

3/ Limited to deliveries when Trojan Generating Plant is not in operation.

4/ Upon Bonneville's request, the Company shall provide evidence of the obligation to provide station service and the amounts and conditions of such obligation.

5/ Bonneville shall integrate power pursuant to this agreement from a Point of Integration under this agreement to Boardman for the Company to the extent of obligations to replace the power of Pacific Northwest Generating Company and Idaho Power Company (or their assignees) when Boardman is displaced. Assignees shall mean any utility whose rights to the power have been assigned under a firm contract for a period of 12 months or more, and the assignee has the means of receiving the power. The Company shall provide evidence of this obligation at Bonneville's request.

6/ UFT Charges covered under a separate transmission agreement Contract No. DE-MS79-84BP91673.

C. Use-of-Facilities Methodology and Charges.

1. Methodology for Joint Use-of-Facilities Charges. 1/

$$\text{Unit Charge} = \frac{(\text{Investment})(\text{Annual Cost Ratio})\ 2/ + \text{Annual Operation and Maintenance}\ 3/}{\text{Noncoincidental Peak Demand}} = \$/\text{kW-yr}$$

$$\text{Monthly Charge} = \frac{(\$/\text{kW-yr})(\text{Trans. Demand})}{12\ \text{months}} = \$/\text{kW-mo.}$$

2. Methodology for Sole Use-of-Facilities Charges. 1/

$$\text{Unit Charge} = (\text{Investment})(\text{Annual Cost Ratio})\ 2/ + \text{Annual Operation and Maintenance}\ 3/ = \$/\text{yr.}$$

$$\text{Monthly Charge} = \frac{(\$/\text{yr})}{12\ \text{months}} = \$/\text{mo.}$$

1/ The methodology for Joint Use-of-Facilities Charges and Sole Use-of-Facilities Charges is an application of the UFT-83 rate schedule.

2/ Annual Cost Ratio from the most recent "Annual Financial Requirements for BPA Transmission System", as a percentage of plant investment without O&M.

3/ Annual Operation & Maintenance from the most recent "Actual O&M Costs and Service Lives for Main Grid Substation Components and Transmission Lines".

D. Description of Points of Integration and Points of Delivery.

These are definitions only. Designations of these points as either Points of Integration or Points of Delivery are in Part A or Part B of this Exhibit.

1. JOHN DAY SUBSTATION:

Location: the points in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV.

2. BIG EDDY SUBSTATION:

Location: the points in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus;

Voltage: 230 kV.

3. GARRISON SUBSTATION:

Location: the points in the Government's Garrison Substation where the line terminals of the Garrison-Townsend lines are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: in the Government's Garrison Substation, in the 500 kV circuits over which such Electric Power is made available to Bonneville.

4. PEARL SUBSTATION:

Location: the point in the Government's Pearl Substation where the 230 kV facilities of the parties hereto are connected;

Voltage: 230 kV;

Metering: in the Government's Pearl Substation, in the 230 kV circuit over which such Electric Power is delivered.

5. ROCKY REACH SWITCHING STATION:

Location: the point in Chelan County PUD's (PUD) switching station where the 230 kV facilities of PUD and the Government are connected;

Voltage: 230 kV.

6. DOUGLAS SWITCH YARD:

Location: the point in the Douglas County PUD's (Douglas) Douglas Switch yard where the 500 kV facilities of the Government and Douglas are connected;

Voltage: 500 kV.

7. MIDWAY SUBSTATION:

Location: the points in the Government's Midway Substation where the 230 kV facilities of the Government and Grant County PUD are connected;

Voltage: 230 kV.

8. VANTAGE SUBSTATION:

Location: the points in the Government's Vantage Substation where the 230 kV facilities of the Government and Grant County PUD are connected;

Voltage: 230 kV;

Metering: in the Government's Vantage Substation, in the 230 kV circuits over which such Electric Power flows.

9. MCLOUGHLIN SUBSTATION:

Location: the point in the Government's McLoughlin Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Government's McLoughlin Substation, in the 230 kV circuit over which such Electric Power flows.

10. RIVERGATE SUBSTATION:

Location: the point adjacent to the Company's Rivergate Substation on structure 8/2 of the Government's Ross-Rivergate 230 kV line where the facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Company's Rivergate Substation, in the 230 kV circuit over which such Electric Power flows;

Exception: there shall be no adjustment for losses between the point of delivery and the point of metering.

11. TROJAN SWITCHING STATION:

Location: the points in the Company's Trojan Switching Station where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Company's Trojan Switching Station, in the 230 kV circuits over which such Electric Power flows.

12. BETHEL SUBSTATION:

Location: the point in the Company's Bethel Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Company's Bethel Substation, in the 230 kV circuit over which such Electric Power flows.

13. C. W. PAUL SUBSTATION:

Location: the points in the Government's C. W. Paul Substation where the 500 kV facilities of the Government and the Company are connected;

Voltage: 500 kV.

14. SLATT SUBSTATION:

Location: the point in the Government's Slatt Substation where the 500 kV facilities of the Government and the Company are connected;

Voltage: 500 kV;

Metering: in the Government's Slatt Substation, in the 500 kV circuit over which such Electric Power flows.

15. ALLSTON SUBSTATION:

Location: the point in the Government's Allston Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Government's Allston Substation, in the 230 kV circuit over which such Electric Power flows.

16. D.R. KEELER SUBSTATION

Location: the point in the Government's D.R. Keeler Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Government's D.R. Keeler Substation, in the 230 kV circuit over which such Electric Power flows.

Losses

A. Losses Resulting From Transmission Pursuant to the Integration of Resources (IR) Rate Schedule.

Loss Factor

1.6%

B. Losses Resulting From Nonfirm Transmission Pursuant to the Energy Transmission (ET) Rate Schedule.

Loss Factor

1.6%

Other Transmission Agreements Between the Parties

Contract Number	Point of Interconnection	Point(s) of Delivery	Resource	Expiration Date
DE-MS79-86BP92260	Slatt Substation	John Day Substation	Boardman Project	12/31/2013
DE-MS79-85BP91882	Ione Substation	McLoughlin Substation	Kinzua Cogeneration Project	3/18/2005
DE-MS79-85BP92187	Satsop Substation	Keeler Substation	WNP 3	1/
14-03-47311	Various project interconnection points	As shown in Exhibit C to the contract	Canadian Entitlement Exchange Agreement	2/
14-03-47451 (Rocky Reach) 14-03-47453 (Wells) 14-03-47454 (Priest Rapids) 14-03-47455 (Wanapum)	Various project interconnection points	As shown in Exhibit C to the respective contracts	Canadian Entitlement Allocation Agreement	3/31/2003

1/ See WNP 3 Settlement Exchange Agreement, Section 1 (i), Definition and Explanation of Terms, "Exchange Termination Date"

2/ Later of 3/31/2003 or the date all bonds are paid.

(VS6-PMT-3188e)

Contract No. DE-MS79-87BP92340

INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

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Exhibit A Sharing of Costs for Reliability Improvements and other Projects

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Exhibit E Northwest AC Intertie Losses

Exhibit F Calculation of Charges for Access to Southern Oregon Substation

Exhibit G Calculation of DC Intertie Losses

- -

This INTERTIE AGREEMENT, executed July 29, 1988, by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PORTLAND GENERAL ELECTRIC COMPANY (Portland), a corporation organized and existing under the laws of the State of Oregon.

W I T N E S S E T H :

WHEREAS Bonneville and Portland are owners of facilities that comprise the existing Joint AC Intertie; and

WHEREAS Bonneville and Portland are parties to Contract No. 14-03-55063 (Intertie Operations Agreement), and to Contract No. DE-MS79-84BP91883 (Intertie Settlement Agreement), which provided rights and responsibilities of

the parties regarding the Joint AC Intertie and which shall expire on December 15, 1988, unless extended or replaced; and

WHEREAS Bonneville and Portland desire to replace the Intertie Operations Agreement and Intertie Settlement Agreement with this Intertie Agreement; and

WHEREAS Bonneville and Portland desire to jointly operate their AC Intertie facilities as a single system in order to realize the full benefits of the combined facilities and to permit the ongoing use of the facilities for delivery and receipt of power and energy as described in this Agreement.

WHEREAS Bonneville, Portland, Pacific Power & Light Company (Pacific), and the Bureau of Reclamation entered into Contract No. 14-03-59840 (Malin Construction and Operations Agreement), Bonneville and Portland entered into Contract No. 14-03-29225 (Malin Construction Trust Agreement), and Contract No. 14-03-63627 (Malin Operation and Maintenance Trust Agreement) that include terms and provisions for facilities in the Joint AC Intertie in the Malin Substation; and

WHEREAS Bonneville and Portland entered into Contract No. 14-03-56747 (Grizzly Trust Agreement), Contract No. DE-MS79-86BP92277 (Grizzly Construction Trust Agreement), and Contract No. 14-03-73941 (Grizzly Operation and Maintenance Trust Agreement) that include terms and provision for facilities in the Joint AC Intertie at the Grizzly Substation; and

WHEREAS Bonneville and Pacific entered into Contract No. DE-MS79-86BP92299 (Pacific Intertie Agreement) that, among other things, gives Bonneville certain rights to establish a Plan-of-Service for the upgrade of the Northwest AC Intertie, and to construct and interconnect such intertie with Pacific's facilities; and

WHEREAS the California-Oregon Transmission Project (COTP) in California may be constructed and, if it is, Bonneville may desire to upgrade the Northwest AC Intertie to meet the expected increase in capacity, in which event Portland may desire to upgrade Portland's facilities in the Joint AC Intertie; and

WHEREAS Bonneville and Portland may, in the future, desire to further upgrade the facilities of the AC Intertie such that the Rated Transfer Capability of the AC Intertie is increased beyond the Transfer Capability of the COTP; and

WHEREAS Portland desires continuing ability to schedule power and energy for delivery to Pacific Southwest utilities at the Southern Oregon Substation; and

WHEREAS Bonneville and Portland agree to provide for the resolution of other agreements including a General Transfer Agreement, an Integration of Resources (IR) Agreement, and an exchange of a share of Portland's AC Rated Transfer Capability for an equal share of Bonneville's DC Rated Transfer Capability; and

WHEREAS Bonneville and Portland desire to resolve other outstanding issues regarding use of each other's system; and

WHEREAS nothing in this Intertie Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Agreement;

NOW, THEREFORE, in order to realize the full benefits from the facilities individually and jointly owned by the parties, to provide for the continuing use of those facilities, and to provide for planning, designing, operating, modifying, constructing, maintaining, and upgrading the individually and jointly owned facilities, known as the Joint AC Intertie, the parties hereto agree to the following:

1. Termination of Prior Agreements. The Intertie Operations Agreement and Intertie Settlement Agreement are hereby terminated on the Effective Date of this Agreement, but all obligations accrued thereunder are hereby preserved until satisfied.

2. Term of Agreement.

(a) With the exception of the provisions for operating and scheduling, which shall continue for 30 days from the Effective Date, this Agreement shall be effective on the date of execution (Effective Date) and shall continue in effect so long as the facilities of the Joint AC Intertie are in existence and operable.

(b) Should this Agreement terminate earlier than specified in subsection 2(a) for any reason except material breach of contract by either party, and the parties fail to agree to a replacement agreement, the parties agree to operate their jointly owned and separately owned facilities in such a manner to permit the continued use of the facilities for delivery and receipt of power and energy as described in this Agreement. Other than as excepted above, the parties intend this obligation to survive such earlier termination.

(c) Bonneville agrees not to participate in any renegotiation of provisions in the Pacific Intertie Agreement between Pacific and Bonneville effecting: (1) the ownership, operation, maintenance, or modification of the Joint AC Intertie; (2) the Rated Transfer Capability of the Northwest AC Intertie; or (3) Portland's right to make deliveries at Southern Oregon Substation as provided in subsection 8(c) of this Agreement, unless Portland is allowed to participate in the negotiations. In addition, Portland agrees not to participate in any negotiations with Pacific effecting: (1) ownership, operation, maintenance, or modification of the Northwest AC Intertie; or (2) the Rated Transfer Capability of the Northwest AC Intertie, unless Bonneville is allowed to participate in the negotiations.

(d) Bonneville and Portland agree to apply their best efforts to retain rights to deliver power and energy through Southern Oregon Substation.

3. Exhibits. Exhibits A through F are incorporated as part of this Agreement.

4. Definitions.

(a) COTP. The 500 kV transmission line proposed by the California-Oregon Transmission Project, or a successor line, which will operate in parallel with the existing 500 kV AC Intertie in California and that would increase the Rated Transfer Capability of the Northwest AC Intertie beyond the present capability of 3200 MW to as much as 4800 MW.

(b) DC Intertie. The DC Intertie consists of the Celilo converter station and the direct current line extending from the Celilo converter station to the Nevada-Oregon border, which are solely owned by Bonneville and which presently have a Rated Transfer Capability of approximately 2000 MW.

(c) DC Terminal Expansion. The planned increase in DC Intertie Rated Transfer Capability resulting from modifications to the Celilo and Sylmar Substations and the addition of new equipment to existing transmission facilities for the support of the DC Intertie. The planned Rated Transfer Capability of the Terminal Expansion is approximately 1100 MW, for a total DC Intertie Rated Transfer Capability of approximately 3100 MW.

(d) FCRTS or Federal Columbia River Transmission System. The transmission facilities of the Federal Columbia River Power System that include all transmission facilities owned and operated by Bonneville, and other regional facilities for which Bonneville has obtained transmission rights.

(e) Joint AC Intertie. For purposes of this Intertie Agreement, the Joint AC Intertie consists of alternating current (AC) transmission facilities, located in the State of Oregon, for transferring power and energy between the Pacific Northwest and California as follows: two 500 kV transmission lines extending from the John Day Substation to the Malin Substation, portions of John Day, Grizzly, and Malin Substations and the Bakeoven, Sand Springs, Fort Rock, and Sycan Compensation Stations. Consistent with the procedure specified in subsection 9(a), any modifications, additions, improvements, or other alterations to facilities in the Joint AC Intertie shall also become part of the Joint AC Intertie.

(f) Joint Intertie Scheduling Office. The group of Bonneville, Portland, and Pacific schedulers, which is presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, and whose representatives are appointed from time-to-time to schedule energy over the Northwest AC Intertie.

(g) Northwest AC Intertie. The Northwest AC Intertie consists of those facilities in the Joint AC Intertie; and a portion of the Buckley-Summer Lake transmission line, Bonneville's rights in the 500 kV Summer Lake-Malin transmission line, and, should Bonneville require, the use of the 500 kV Meridian-Malin transmission line, the Southern Oregon Substation, and Bonneville's ownership of or rights to use the planned 500 kV Alvey-Meridian transmission line. Any modifications, additions, improvements, or other alterations to facilities in the Northwest AC Intertie shall also become part of the Northwest AC Intertie.

(h) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the parties, and operational limitations as a result of among other things line or equipment outages, stability limits, or loopflow.

(i) Plan-of-Service. The project plans developed to realize an increase in the Rated Transfer Capability of the Northwest AC Intertie from 3200 MW up to approximately 4800 MW, which project plans shall include but are not necessarily limited to plans, schedules, costs, and facility and equipment requirements.

(j) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry existing prior to the subject action or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(k) Rated Transfer Capability. The capability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(l) Southern Oregon Substation. The proposed substation where the transmission line that interconnects with the COTP connects with the Northwest and Joint AC Interties in the Pacific Northwest.

(m) Unused Operational Transfer Capability. Operational Transfer Capability not being used during a given hour for a party's own schedules.

5. Ownership.

(a) Facilities in the Joint AC Intertie. Ownership of existing facilities is as follows:

(1) Bonneville has constructed and owns two 500 kV AC circuits from its John Day Substation to the Grizzly Substation, including two 500 kV terminal positions in said John Day Substation, and one 500 kV AC circuit from the Grizzly Substation to the Malin Substation (Grizzly-Malin No. 1

line). Bonneville also has constructed and owns the Bakeoven, and its Sand Springs, Fort Rock, and Sycan Compensation Stations.

(2) Portland has constructed and owns one 500 kV AC circuit from the Grizzly Substation to the Malin Substation (Grizzly-Malin No. 2 line). Portland also has constructed and owns its Sand Springs, Fort Rock, and Sycan Compensation Stations.

(3) Ownership of all facilities at the Grizzly Substation is as defined in the Grizzly Trust Agreement and the Grizzly Construction Trust Agreement.

(4) Ownership of all facilities at the Malin Substation is as defined in the Malin Construction and Operation Agreement and the Malin Construction Trust Agreement.

(b) By this Agreement, neither Bonneville nor Portland transfers to the other party ownership of existing or future facilities. While the provisions of section 8 provide Bonneville and Portland with scheduling rights based on the Rated Transfer Capability of the Northwest AC Intertie, there is no intention to transfer from one party to the other party any ownership in such facilities beyond those facilities presently owned by that party.

6. Operation of Northwest AC Intertie.

(a) Single System Operation. Bonneville and Portland, as between each other, hereby agree to operate their respective jointly owned and separately owned Northwest and Joint AC Intertie facilities as a single system so as to maximize, consistent with Prudent Utility Practice, the Rated and Operational Transfer Capability of the combined facilities.

(b) Committees.

(1) Management Committee. Bonneville and Portland shall form a Management Committee, consisting of one senior executive representative and an alternate from each organization possessing authority to commit their respective organization. The Management Committee shall oversee implementation of all provisions of this Agreement; designate representatives to and oversee the work of the Operations and Scheduling Committee and Engineering Committee; and resolve any disputes. Decisions of the Management Committee shall be by unanimous consent.

(2) Operation and Scheduling Committee. Among the duties of the Operation and Scheduling Committee are developing principles to guide the decisionmaking of the Operator and Joint Scheduling Office, and when the need arises to review the operation, maintenance, and scheduling of the Joint AC Intertie for consistency with the principles. The Management Committee may assign other duties to the Operation and Scheduling Committee where appropriate.

(3) Engineering Committee. Among the duties of the Engineering Committee are reviewing the plans for capital investments to the Joint AC Intertie. The Management Committee may assign other duties to the Engineering Committee where appropriate.

(c) Operator. Bonneville shall be the operator for the Northwest AC Intertie. As such, Bonneville shall be responsible for the dispatch of the Northwest AC Intertie in accordance with Prudent Utility Practice and the principles for operation developed by the Operation and Scheduling Committee, established pursuant to paragraph 6(b)(2). The duties of the operator include, but are not limited to, determining: (1) the Operational Transfer

Capability of the Northwest AC Intertie; (2) emergency outages; and (3) switching orders. In making such determination, Bonneville shall give fair consideration to Portland's interests in such matters, consistent with Prudent Utility Practice, to the extent those interests have been expressed to Bonneville in writing.

(d) Remedial Actions. Bonneville and Portland shall jointly develop through the Engineering Committee a plan for remedial actions, including generator dropping, required to support the Rated Transfer Capability of the Northwest AC Intertie. Each party shall provide, and be financially responsible for or make arrangements for, generator dropping or other remedial actions required to achieve the provisions of the plan. Each party's responsibility for such remedial actions, which may include generator dropping, shall be determined by dividing the party's share of Rated Transfer Capability in the Northwest AC Intertie by the total Rated Transfer Capability of the Northwest AC Intertie.

7. Shares of Rated Transfer Capability.

(a) Rated Transfer Capability at or below 3200 Megawatts (MW). During such time that the Rated Transfer Capability of the Northwest AC Intertie is less than or equal to 3200 MW, Portland's share of Rated Transfer Capability shall be equal to 25 percent of the Rated Transfer Capability of the Northwest AC Intertie. As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability of the Northwest AC Intertie shall be equal to 75 percent of the Rated Transfer Capability of the Northwest AC Intertie.

(b) Rated Transfer Capability greater than 3200 MW but not more than 4800 MW. During such time that the Rated Transfer Capability of the Northwest AC Intertie is greater than 3200 MW up to and including 4800 MW, Portland's share of Rated Transfer Capability shall be the share specified in subsection 7(a) plus a share of the increased Rated Transfer Capability in the

ratio of 150/1600 times the increase in Rated Transfer Capability above 3200 MW. As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability shall be the share specified in subsection 7(a) plus a share of the increased Rated Transfer Capability in the ratio of 1450/1600 times the increase in Rated Transfer Capability above 3200 MW.

(c) Rated Transfer Capability greater than 4800 MW. Bonneville and Portland agree that any project to increase the Rated Transfer Capability of the Northwest AC Intertie above 4800 MW shall only be accomplished by distributing the increased Rated Transfer Capability such that at least two-thirds of the increase is distributed to the Joint AC Intertie. Portland shall have the right to participate in any such project to increase the Rated Transfer Capability of the Northwest AC above 4800 MW if Portland chooses to share in such increases. If so, both Portland's cost sharing and increased share of Rated Transfer Capability shall be at a ratio of 950/3200 of the project costs and increased Rated Transfer Capability so attributed to the Joint AC Intertie. Ownership of facilities providing the increased Northwest AC Intertie Rated Transfer Capability shall be determined by negotiation with and between facility owners.

8. Transmission Rights.

(a) Determination of Rated Transfer Capability and Operational Transfer Capability. Bonneville and Portland shall jointly determine the Rated Transfer Capability of the Joint AC Intertie. Portland agrees that Bonneville may determine the Rated Transfer Capability of the Northwest AC Intertie, provided such determination is in keeping with Prudent Utility Practice, and further provided that Bonneville consults with Portland and reasonably incorporates Portland's technical opinion.

(b) Intertie Scheduling Rights.

(1) During times when the Northwest AC Intertie Operational Transfer Capability is less than the Northwest AC Intertie Rated Transfer Capability, Bonneville and Portland's scheduling rights shall be limited to an amount determined by multiplying the Northwest AC Intertie Operational Transfer Capability by the ratio of the party's share of Northwest AC Intertie Rated Transfer Capability to the total Northwest AC Intertie Rated Transfer Capability.

(2) Bonneville and Portland, as between each other, have the exclusive right to use their own share of Northwest AC Intertie Operational Transfer Capability to schedule power or energy for delivery to and from Pacific Southwest utilities without regard to the ownership of the power or energy scheduled and hereby relinquish any rights to make use of the other party's Unused Operational Transfer Capability. Either party, at its discretion, may make its Unused Operational Transfer Capability available to the other party so that the other party may schedule up to its Rated Transfer Capability.

(c) Portland's Rights to Access at Southern Oregon Substation.

(1) Once the Southern Oregon Substation, and the facilities connecting it to the Joint AC Intertie, and the COTP, and the facilities connecting it to the Southern Oregon Substation, are in operation such that the Rated Transfer Capability of the Northwest AC Intertie has been increased to above 3200 MW, Portland shall have the right to schedule power or energy for delivery at all times to and from Pacific Southwest utilities through the Southern Oregon Substation as follows:

(A) If the COTP and the presently existing AC Intertie lines in California are operated as a single system (i.e., integrated with the

existing AC Intertie system such that there is an equivalent sharing among the COTP owners and existing intertie owners of transfer capability under all conditions), Portland may schedule up to its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1).

(B) If the COTP and the presently existing AC Intertie lines in California are not operated as a single system, Portland may schedule up to one third of its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1).

(2) Such delivery right is intended to continue upon the terms and conditions specified in this subsection 8(c) for as long as the Southern Oregon Substation and the facilities connecting it to the COTP are in existence and operable and Bonneville has rights to schedule to Southern Oregon Substation. Should this Agreement terminate earlier than specified in subsection 2(a) for any reason except material breach of contract by either party, and the parties fail to agree to a replacement agreement, the rights of Portland under this subsection 8(c) shall survive for the period stated above, contingent upon Portland's satisfaction of its payment obligation under paragraph 8(c)(3). Therefore, other than as excepted above, the parties intend this obligation to survive such earlier termination.

(3) In consideration for the right to make deliveries to Southern Oregon Substation in paragraph 8(c)(1), Portland shall pay Bonneville 950/4800 of the annual cost of the Southern Oregon Substation, facilities connecting it to the Joint AC Intertie and the facilities connecting the Southern Oregon Substation to the COTP. All such facilities and their estimated costs are shown in Exhibit F. Bonneville and Portland agree

that the estimated investment costs and resultant annual costs shall be revised to reflect actual construction costs. The methodology to compute the annual cost of such facilities is described in Exhibit F and an example of the calculation applying such methodology is provided in Exhibit F. Such annual charge shall be billed and paid on a monthly basis according to the billing and payment provisions in Portland's Power Sales Agreement (Contract No. DE-MS79-81BP90425).

(4) Bonneville shall maintain the Southern Oregon Substation, the facilities connecting it to the Joint AC Intertie, and the facilities connecting the Southern Oregon Substation to the COTP according to Prudent Utility Practice so as to sustain their ability to transfer power and energy. In the event that these facilities are unable to transfer power and energy as a result of Bonneville's failure to maintain or replace such facilities such that Portland cannot transfer its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1), through the Southern Oregon Substation for a period in excess of 120 days, then Portland shall be obligated to pay the annual charge specified in paragraph 8(c)(3) minus one-half the annual charge divided by 365 days times the number of days in which Portland is unable make such transfers (annual charge - [(1/2 annual charge/365 days) X days Portland is unable to schedule at Southern Oregon Substation]).

(d) FCRTS Wheeling to Northwest AC Intertie.

(1) Except as provided in paragraph 8(d)(2), all of Portland's schedules to Pacific Southwest utilities on the Northwest AC Intertie shall be deemed to be delivered at John Day Substation, or if Bonneville establishes other Northwest AC Intertie points of delivery, at Portland's

request such deliveries may be deemed to be delivered to such other points of delivery.

(2) Except when Portland is accepting schedules under the provisions of paragraph 8(d)(3), up to the greater of 150 MW of Portland's schedules to Pacific Southwest utilities, or an amount equal to the actual energy produced from Portland's Round Butte and Pelton projects when those projects are actually producing energy, not to exceed the capacity of the transformer for the Round Butte-Grizzly line, shall be deemed to be delivered over Portland's facilities to the Grizzly Substation.

(3) Portland can schedule power and energy from Pacific Southwest utilities over the Grizzly-Bethel line up to the actual east to west flow on the Grizzly-Round Butte line as metered at Grizzly.

(4) Transmission arrangements over the FCRTS, other than the Joint or Northwest AC facilities, shall be as provided in subsection 15(c).

9. Modification of and Addition to Facilities.

(a) Unless it has obtained the written consent of the other party, such consent not to be unreasonably withheld, neither party shall make any modifications, additions, improvements, or other alterations to facilities in the Joint AC Intertie. Ownership of modifications, additions, improvements, or other alterations made with such consent shall be as specified in the Malin Construction and Operation Agreement, the Grizzly Trust Agreement, and the Grizzly Construction Trust Agreement, where appropriate, or as agreed by the parties in advance of the performance of such work.

(b) Portland and Bonneville hereby consent to a Plan-of-Service for modifications and additions to the Joint AC Intertie to increase the Rated Transfer Capability of the Northwest AC Intertie to 4800 MW provided that such Plan-of-Service conforms to the Third AC Intertie Project Diagram,

incorporated herein as Exhibit C. Bonneville and Portland shall share, in accordance with the percentages specified in Exhibit B, the actual cost of the facilities identified in the Plan-of-Service.

(c) In the event this Agreement terminates for any reason and implementation of such Plan-of-Service causes Portland to lose its physically and electrically connected transmission path through facilities in which it has ownership, from its service territory via Round Butte, through Grizzly substation to Malin substation over the Grizzly-Malin Number 2 line, Bonneville agrees to restore and share equally the costs of such restoration of Portland's continuous connection of facilities owned by Portland.

(d) Portland agrees that Bonneville shall have the right to plan, design, locate, construct, and own the Southern Oregon Substation and associated interconnection to the COTP. Should the basic configuration of the Southern Oregon Substation materially change from that shown in Exhibit C such that Portland's access under subsection 8(c) to the substation and the Pacific Southwest utilities is reduced or such that Portland's charges under paragraph 8(c)(3) substantially increase, then Bonneville will seek Portland's consent, such consent not to be unreasonably withheld.

(e) Portland hereby consents to any modifications consistent with Prudent Utility Practice to the Joint AC Intertie, at Bonneville's expense, necessary to accomplish the DC Terminal Expansion project up to a total DC Intertie Rated Transfer Capability of approximately 3100 MW, including the modifications shown in Exhibit A.

(f) Bonneville and Portland hereby consent to undertake those modifications to facilities in the Joint AC Intertie, as specified in Exhibit A, necessary to implement the reliability improvement projects. Portland shall permit Bonneville to make the modifications to the Malin,

Grizzly, and Fort Rock Substations specified in Exhibit A, or Portland shall make such modifications. Portland shall pay the share of the actual costs of the modifications specified in Exhibit A. Bonneville and Portland's ownership of such modifications at Malin and Grizzly shall be equal to the percentages specified in Exhibit A.

10. Financing by Portland

(a) At Bonneville's request, Portland shall arrange to finance Bonneville's costs associated with the development of the project to increase the Northwest AC Intertie Rated Transfer Capability from 3200 MW up to approximately 4800 MW as provided for in this Agreement.

Such request shall be made in writing and Portland shall make such arrangements within 60 days after mutual consultations on alternatives. (Time is of the essence.) Bonneville shall have the right to approve or disapprove such arrangements prior to the sale or issuance of any obligation or financing arranged by Portland pursuant to this paragraph.

(b) The proceeds of any financing, net of issuance costs, shall be paid into a trust. Bonneville and Portland shall mutually agree on a form of trust agreement and the selection of a trustee. The trustee shall pay construction costs or amounts owing to Portland, as applicable, together with payments of any capitalized carrying financing costs incurred during construction and capitalized carrying costs on such costs, if any.

(c) Portland shall attempt to obtain the least possible cost financing available. Portland shall not be required to seek financing based on its own credit unless financing based solely on Bonneville's payment obligation is not available. Portland need not make available to Bonneville any financing opportunities that Portland intends to use to finance other Portland costs or to retire Portland debt. Portland will not use any financing opportunity that

results from any financing proposal made at Bonneville's request to finance any other Portland costs.

(d) Portland need not attempt any formal financing that: (a) may cause Portland General Corporation to become a nonexempt Holding Company under the Public Utility Holding Company Act of 1935, 15 USC §79 et. seq.; (b) would be contrary to the restrictions of any law, regulation, judicial decree, or order of any applicable jurisdiction; or (c) would be contrary to any Portland bond indenture, preferred stock covenant, or other Portland financial commitment.

(e) Bonneville shall make all financing payments as stipulated in the mutually agreed upon financing arrangement.

11. Maintenance of Facilities.

(a) Each party is responsible for performing maintenance on and reinforcing its respective solely owned facilities so as to maintain the Rated Transfer Capability of the Northwest AC Intertie. Maintenance on the jointly owned facilities at Grizzly and Malin substations are provided for in the Grizzly Operation and Maintenance Trust Agreement and the Malin Operations and Maintenance Trust Agreement, respectively.

(b) Each party is responsible for performing maintenance on its respective existing facilities so as to maintain the Rated Transfer Capability of the existing DC Intertie and the DC Terminal Expansion. Bonneville is responsible for performing maintenance on the existing DC Intertie facilities and the DC Terminal Expansion facilities so as to maintain the Rated Transfer Capability of the Northwest AC Intertie.

(c) Each party shall carry out the requirements of section 11 consistent with Prudent Utility Practice.

(d) Bonneville and Portland shall negotiate in good faith a separate joint maintenance agreement for the jointly owned facilities of the Joint AC

Intertie to replace the existing agreements for maintenance.

12. Scheduling.

(a) Bonneville and Portland shall schedule through the Joint Intertie Scheduling Office all schedules to and from utilities in the Pacific Southwest to be delivered at the Malin and Southern Oregon Substations.

(b) Portland shall provide the Joint Scheduling Office an actual schedule of the generation at the Round Butte and Pelton projects by 1000 hours of the following workday for the previous day or days. Such schedule shall be consistent with section 8(d)(2) of this Agreement.

13. Northwest AC Intertie Charges.

(a) Charges for Portland's Own Schedules. Bonneville shall not assess Portland any charge to schedule power and energy for delivery to and from Pacific Southwest utilities over the Northwest AC Intertie on any hour up to Portland's share of the Rated Transfer Capability, as such share may be reduced pursuant to subsection 8(b)(1).

14. Losses. Bonneville and Portland shall replace losses for schedules on the Northwest AC Intertie as provided in Exhibit E.

15. Other Agreements.

(a) Agreement to an Exchange of Rights of Use of AC for DC Capability. Bonneville and Portland agree to terms and conditions for an exchange of the right to use a amount of Portland's share of the Northwest AC Intertie Rated Transfer Capability for a right to use an equal amount of Bonneville's DC Intertie Rated Transfer Capability as provided in Exhibit D to this Agreement.

(b) General Transfer Agreement. Bonneville and Portland agree to ~~the~~ negotiate a new general transfer agreement to be executed by January 1, 1989. During the negotiation period, Bonneville and Portland agree to continue the

existing transfer services according to the terms and provisions of Contract No. DE-MS79-83BP91011 as such agreement has been amended.

(c) IR Agreement.

(1) Bonneville and Portland shall negotiate in good faith a general transmission agreement (IR Agreement) to be executed by January 1, 1989. Such agreement shall be executed concurrently with the general transfer agreement and shall include provisions for delivery from Portland's resources to the Northwest AC and DC Intertie points of delivery as well as to Portland's system points of delivery.

(2) Deliveries of power and energy over the FCRTS to points of delivery at the Northwest AC Intertie are not provided by this Agreement and must be provided for by separate agreement between Bonneville and Portland. However, until January 1, 1989, Bonneville agrees to provide Portland with the right to deliver energy to the Northwest AC Intertie point of delivery which would otherwise be delivered to Portland's system as specified in Contracts Nos. 14-03-001-13437, 14-03-001-13773, 14-03-28002, and 14-03-41848 (Mid-Columbia Agreements) subject in all other respect to the applicable terms and conditions of such agreements. After January 1, 1989, if an IR Agreement and a general transfer agreement have not been executed, half of Portland's schedules to the Northwest AC Intertie point of delivery will continue as specified above, but the other half of Portland's schedules shall be required to be delivered at Portland's system and shall be subject to Bonneville's rate schedule for nonfirm transmission and losses for subsequent delivery to the Northwest AC Intertie point of delivery, unless otherwise agreed by Bonneville and Portland.

(d) Extension of Existing Agreements. Bonneville and Portland agree that for the purpose of defining the term of the Malin Construction and Operations Agreement, Malin Operation and Maintenance Trust Agreement, and Grizzly Operation and Maintenance Trust Agreement, this Agreement shall be considered to be a renewal by a similar agreement of the Intertie Operations Agreement and the Intertie Settlement Agreement.

(e) Agreements for Implementation of this Agreement. In addition to the above agreements, Bonneville and Portland agree to negotiate in good faith any additional agreements that may be required to implement the terms and conditions of this Agreement, including but not limited to agreements for transmission, and operation and maintenance.

16. Sale or Assignment.

(a) Portland or Bonneville may sell, assign, lease, sublease or otherwise transfer (all hereafter referred to as "transfer") this Agreement, any interest herein or any direct or indirect interest in the Joint AC Intertie facilities or facilities directly affecting the Joint AC Intertie, without the consent of the other party, provided

(1) the agreement by which the transfer is accomplished contains the following language:

"Anything contained in this Agreement to the contrary notwithstanding, the transferor does not by this Agreement transfer any rights or obligations with respect to any of the following activities, and hereby specifically retains all such rights and obligations:

(A) scheduling the use of the transferor's interest (including the interest transferred herein) in the Joint AC Intertie as that interest is established pursuant to the Intertie Agreement between

Portland General Electric Company and the Bonneville Power Administration (Contract No. DE-MS79-87BP92340) executed July 29, 1988, as amended;

(B) operation, maintenance and repair of the Joint AC Intertie facilities (as defined in the Intertie Agreement);

(C) renewals, replacements and additions to the Joint AC Intertie facilities; and

(D) system planning for the Joint AC Intertie."

"Subsequent involuntary transfer, by law or otherwise, of any rights or obligations with respect to any of the foregoing activities shall be subject to the non-transferring owner's prior right to preclude such transfer by, at its election,

(i) remedying any and all defaults; or

(ii) acquiring the interest herein transferred at fair market value and assuming the rights and obligations respecting the foregoing activities."; and

(2) the agreement grants third party beneficiary status to the nontransferring owner with respect to enforcement of the above provisions.

(b) Notwithstanding the provisions of subparagraphs 16(a)(1)(B) and (C) above, the transferor may covenant to the transferee to perform maintenance to keep the Joint AC Intertie facilities in good working order pursuant to Prudent Utility Practice, and to maintain the Rated Transfer Capability (as defined in the above Intertie Agreement between Portland and the Bonneville) of the Joint AC Intertie.

(c) Portland or Bonneville may transfer this Agreement, any interest herein or any direct or indirect interest in the Joint AC Intertie facilities

to an entity or entities if the transferring party is acquired in total by such other entities.

(d) Except as provided in subsections 16(a) and (c) above, Portland and Bonneville agree not to transfer this Agreement, any interest herein, any interest in the Joint AC Intertie facilities or any rights or obligations with respect to the activities listed in paragraph 16(a)(1) above without the written consent of the other party, such consent not to be unreasonably withheld. Wheeling and other transmission contracts which do not transfer legal rights or obligations with respect to scheduling, operations, maintenance, repair, improvement, modification or system planning of the Joint AC Intertie to other parties shall not be considered transfers of interests in this Agreement or in the Joint AC Intertie facilities. Scheduling of wheeling obligations shall be retained by Portland and Bonneville.

(e) A party proposing to transfer an interest in this Agreement or in the Joint AC Intertie facilities shall provide the other party at least 30 days notice prior to the earlier of: (1) the execution of the transfer or grant documents; or (2) filing of the proposed transfer with FERC or its successor agency, if such transfer must be filed with FERC. The party shall provide with such notice a description of the terms and conditions of the proposed transfer sufficient to allow the other party reasonable opportunity to evaluate the proposed transfer with respect to the requirements of this section (including the position of the party giving notice as to whether consent is required pursuant to subsection 16(d)), and shall thereafter provide to the other party copies of all final documents comprising the transfer agreement as early as possible prior to their execution. If the information provided is considered by the party providing such information to

be proprietary and confidential, it shall label such information as proprietary and confidential. The party receiving the above information shall exert best efforts to keep all such labeled information confidential until it has been made public by the other party or others. The receiving party shall take steps necessary to have the information declared "proprietary" or otherwise categorized so as to protect such information from public disclosure to the extent legally allowable under the Federal Freedom of Information Act or similar applicable law or regulation.

(f) The nontransferring party shall notify the other party by the 30th day following actual receipt of the notice and description described in subsection 16(e) (or, if not a working day, the first working day thereafter) of its grant or withholding of consent requested pursuant to subsection 16(d) or its approval or disapproval of a transfer proposed to be made pursuant to subsection 16(a); provided, however, that such time shall be extended to 5 working days after actual receipt of copies of the final documents comprising the transfer or grant if receipt of such documents is on or after the 26th day of the 30-day period and such final documents reflect material changes from documents provided prior to such 26th day. Failure to provide notice of withholding of consent or disapproval within such required periods shall be deemed a grant of consent or approval, as the case may be. The nontransferring party shall be allowed to attend the closing of the transfer and retain all executed copies of its approval until it is satisfied that the final documents do not exhibit material changes from the documents provided earlier. If a party withholds any required consent or disapproves, then such party shall, within 15 days following notice of such withholding or disapproval, provide to the party requesting consent or approval a detailed

written description of the reason(s) consent or approval was withheld.

(g) Portland and Bonneville agree that in the event of any dispute between them concerning the application of this section 16 they shall cooperate fully with each other to obtain final judicial resolution of such dispute in the most expeditious manner possible.

(h) Bonneville hereby consents to Portland's transfers of security interests in this Agreement and the Joint AC Intertie facilities pursuant to the Indenture of Mortgage and Deed of Trust dated July 1, 1945, between Portland and the Marine Midland Trust Company of New York, as supplemented.

(i) The restrictions contained in this section 16, and exceptions thereto, shall apply to any transferee to the same extent they are applicable to the parties to this Agreement.

(j) Transfers of any interest in this Agreement or in the Joint AC Intertie facilities that do not meet the requirements of this section 16 shall be void.

(k) The provisions of this section 16 shall not survive termination of this Agreement.

17. Rules of Law.

(a) Portland and Bonneville agree that each fully participated in the drafting of each provision of this Intertie Agreement. The rule of law interpreting ambiguities against the drafting party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Intertie Agreement or any of its provisions.

(b) The construction and interpretation of this Intertie Agreement shall be governed solely by Federal law.

(c) This Intertie Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither party shall be

under the control of or shall be the agent of or have a right or power to bind the other party without the other's express written consent, except as provided in this Intertie Agreement.

18. Delay of Performance. The time for each act specified in this Intertie Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

19. Continuity of Service.

(a) Either party may temporarily interrupt or reduce deliveries hereunder if such interruption or reduction is necessary or desirable in case of system emergencies, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the electric system of such party. Except in case of emergency and in order that the other party's operations will not be unreasonably interfered with, notice shall be given of any such interruption or reduction, the reason therefore, and the probable duration thereof.

(b) If the operation of either party's transmission system is suspended, interrupted, or interfered with as the result of the occurrence of any event that is specified in subsection 19(a) or any event that is reasonably beyond such party's control (including, but not limited to, the failure or breakdown of generating or transmission facilities, floods, fire, strikes, or acts of God or the public enemy), it shall not be obligated to make deliveries as provided in this agreement, during such time and to such extent as such suspension, interruption, or interference makes it reasonably impracticable to do so, and shall not be liable for any damages sustained by the other party as a result of the failure to make such deliveries during such time.

(c) If the operations of either party are interrupted or curtailed, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

20. Arbitration. In the event of any dispute related to rights or obligations of the parties, or satisfaction thereof, under this Agreement, other than disputes arising under section 16, either party may elect to submit such dispute to nonbinding arbitration. If one party so elects, such party shall notify the other party in writing and both parties shall participate pursuant to the following.

(a) If the parties cannot agree on an arbiter within 10 days of such notification, the notifying party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the parties' written positions. The party electing the arbitration shall first state its position in a letter to the arbiter. The second party shall then state its position in a letter to the arbiter. The first party may then submit a response to the second party's position and the second party may thereafter submit a reply to the first party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the parties otherwise mutually agree. The parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other party.

(d) The arbiter shall provide the parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The parties shall equally share the fee and other costs of the arbiter.

In the event neither party submits the dispute to nonbinding arbitration or if either party elects not to accept the finding of the arbiter, the parties may elect other approaches, including litigation, to resolve the dispute.

21. Metering.

(a) Measurement. Measurement of electric energy and reactive power and of the 60-minute integrated demands for such electric energy flowing between Bonneville's facilities and Portland's facilities at the Grizzly substation shall be determined from measurements made by meters furnished and installed by Bonneville and Portland as agreed.

(b) Test of Meters. Each party to this Agreement shall, at its expense, test its meters mentioned in this Agreement periodically, and, if requested to do so by the other party, shall make additional tests or inspections of such meters, the expense of which shall be paid by such other party unless such additional tests or inspections show such meters to be inaccurate as specified in subsection 21(c). Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Metering equipment found to be defective or inaccurate in any degree shall be adjusted, repaired, or replaced to provide accurate metering.

(c) Adjustment for Inaccurate Metering. If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in subsection 21(b) varies by more than one percent from the measurement made by the standard meter for: (a) the actual period, not to

exceed 6 months, during which such inaccurate measurements were made if such period can be determined; or (b) if not, the period immediately preceding the test of such meter which is equal to one-half the time from the date of the last preceding test of such meter. Such corrected measurements shall be used to recompute the amounts due for the electric energy made available under this contract during such period. If the total amount due for such period as recomputed varies from the total amount due as theretofore computed, the amount of the variance shall be paid to the party entitled thereto within 30 days after the recomputation is made.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By James J. Jura
Administrator

Date July 29, 1988

PORTLAND GENERAL ELECTRIC COMPANY

By

Title Vice President

Date June 29, 1988

(VS6-PMT-2692d)

Sharing of Costs for Reliability Improvements and Other Projects

Description	Planned Energization Date	Total ($000)	PGE Share
1. Reliability Improvements			
Phase 2 (Stability Control Upgrade): Provide new remedial action schemes (RAS) for the AC Intertie and HVDC Intertie. This phase completes a new fully redundant RAS for the HVDC Intertie (two independent control and communication systems). Also this phase will provide the first controller of the new AC Stability Control Scheme including communications support. Output for the second controller (to be installed in Phase 3) are also provided in this phase.			
a. Malin	Jan 1990	932	25%
b. Grizzly	Jan 1990	480	40%
c. Fort Rock	Jan 1989	99	50%
Phase 3 (Stability Control Upgrade): Provide a new AC Intertie stability control system to replace the existing AC Intertie controller. This new control system will utilize some of the communication systems provided under Phase 2. This will complete a fully redundant RAS for the AC Intertie.			
a. Malin	Jan 1990	448	25%
b. Grizzly	Jan 1990	302	40%
2. DC Terminal Expansion Related Projects			
Install a mechanically switched capacitor at Malin Substation	Feb 1989	6,000	0%
Restore High Speed Switching at Fort Rock Compensation Station.	Feb 1989	272	1/

1/ Cost sharing responsibilities shall be as provided in Letter Agreement No. DE-MS79-88BP92446. Ownership of facilities shall be entirely with Portland.

(VS6-PMT-2692d)

Sharing of Costs for Plan-of Service in Joint AC Intertie
1988 ($)

Facility	Estimated Total Cost X 10 3/ [1/]	Allocation PGE	Allocation BPA
Grizzly Substation			
7 PCB's	7309	0%	100%
1 PCB (Round Butte) and associated MOD's	1123	100%	0%
Line Relaying (Grizzly-S. Oregon, Grizzly-Malin #2, Grizzly-J.D. #1 Grizzly-J.D. #2, Grizzly-Buckley Grizzly-S. Lake) and Power System Control, Communication and Data System Facilities	3931	27%	73%
Sand Spring Compensation Station			
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-So. Oregon)	9695 2/	0%	100%
1 - 2400A Cont., 3800A 30 Min. Rated Bank(Grizzly-Malin #2)	6500 5/	100%	0%
Fort Rock Compensation Station			
1 - 2200A Cont., 3000A 30 Min. Rated Bank (Grizzly-So. Oregon)	6277 2/	0%	100%
1 - 2200A Cont., 3000A 30 Min. Rated Bank (Grizzly-Malin #2)	4700 5/	100%	0%
Sycan Compensation Station			
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-So. Oregon)	9535 2/	0%	100%
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-Malin No. 2)	6500 5/	100%	0%

Facility	Estimated Total Cost X 10 3/ [1/]	Allocation PGE	Allocation BPA
Malin Substation			
Line Relaying Malin-S. Oregon (formerly Grizzly-Malin No. 1) Grizzly-Malin No. 2 line and Power System Control, Communication and Data System Facilities	2249	25%	50% 3/
Replace one 500 kV breaker and associated MOD's	775	0%	100%
Line relaying for Malin-S. Oregon #2	211	0%	50% 4/
John Day Substation			
Line Relaying for J.D.-Grizzly #1 & #2, Relaying for Breakers, CT Repl. Power system Controls	2808	0%	100%
Bakeoven Compensation Station			
(Removal and Disposal Costs Only)	1800	0%	100%

1/ Estimated costs include overheads assumed at 30%. Estimated costs are subject to inflation, escalation and minor changes to the plan-of-service.
2/ Estimated costs include removal and disposal costs for PCB contaminated facilities ($600K)
3/ BPA's share is 50%, PGE's share is 25%, PP&L's share is 25%.
4/ BPA's share is 50%, PP&L's share is 50%.
5/ Costs shown are PGE estimates, exclusive of overheads and removal and disposal costs for PCB contaminated facilities.

(VS6-PMT-2692d)

LOWER COLUMBIA AND SNAKE RIVER AREAS

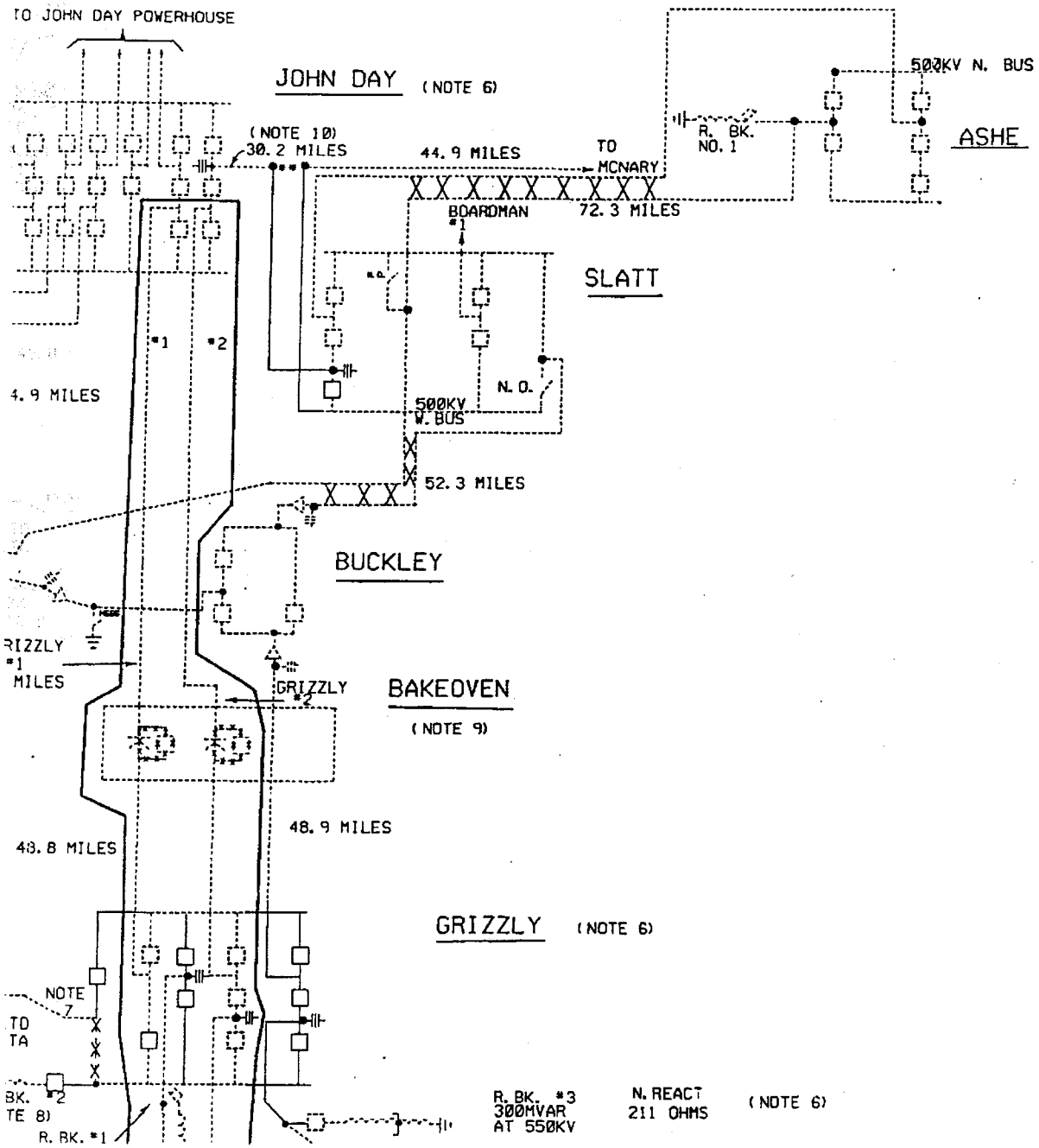


EXHIBIT C, PAGE 1 OF 1
CONTRACT NO. DE-MS79-87BP92340
PORTLAND GENERAL ELECTRIC

NOTES:

1. THIS DIAGRAM SHOWS A NUMBER OF LOAD SERVICE FACILITIES WHICH ARE NOT PART OF THE THIRD AC INTERTIE PROJECT.

2. FOR MORE DETAILED INFORMATION ON THE INDIVIDUAL STATIONS INVOLVED, REFER ALSO TO SHEETS 2 TO 11 AND DRAWING NO. 196480 (EUGENE-MEDFORD PROJECT).

3. TRANSFORMERS SHOWN ARE POTENTIAL ADDITIONS BY PP&L BUT NOT REQUIRED FOR THE THIRD AC INTERTIE PROJECT.

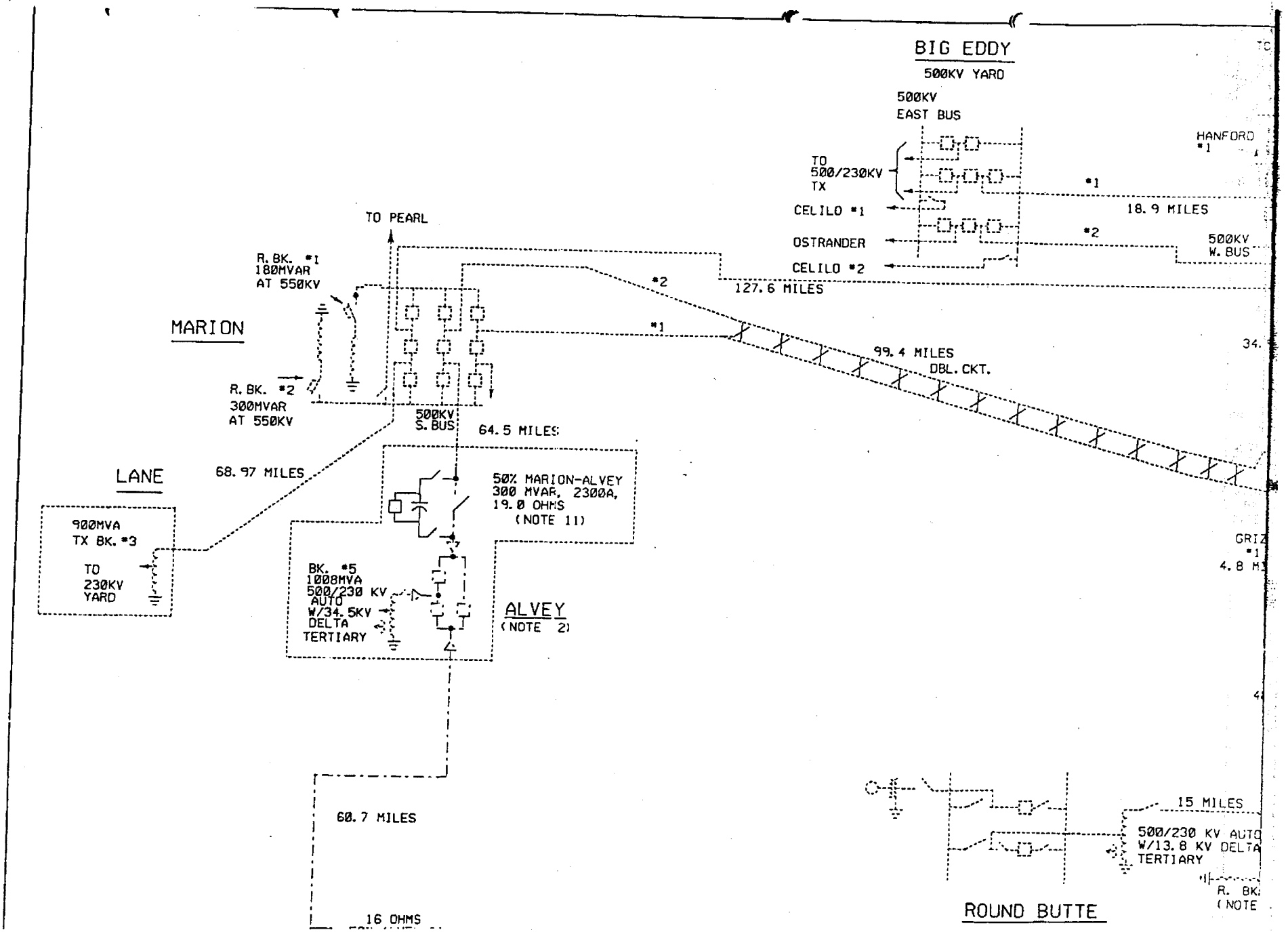
4. TWO 500KV CIRCUIT BREAKERS ADDED AT MALIN ARE ASSOCIATED WITH OVERALL IMPROVEMENT OF INTERTIE PERFORMANCE AND BUDGETED UNDER B.I. 880.

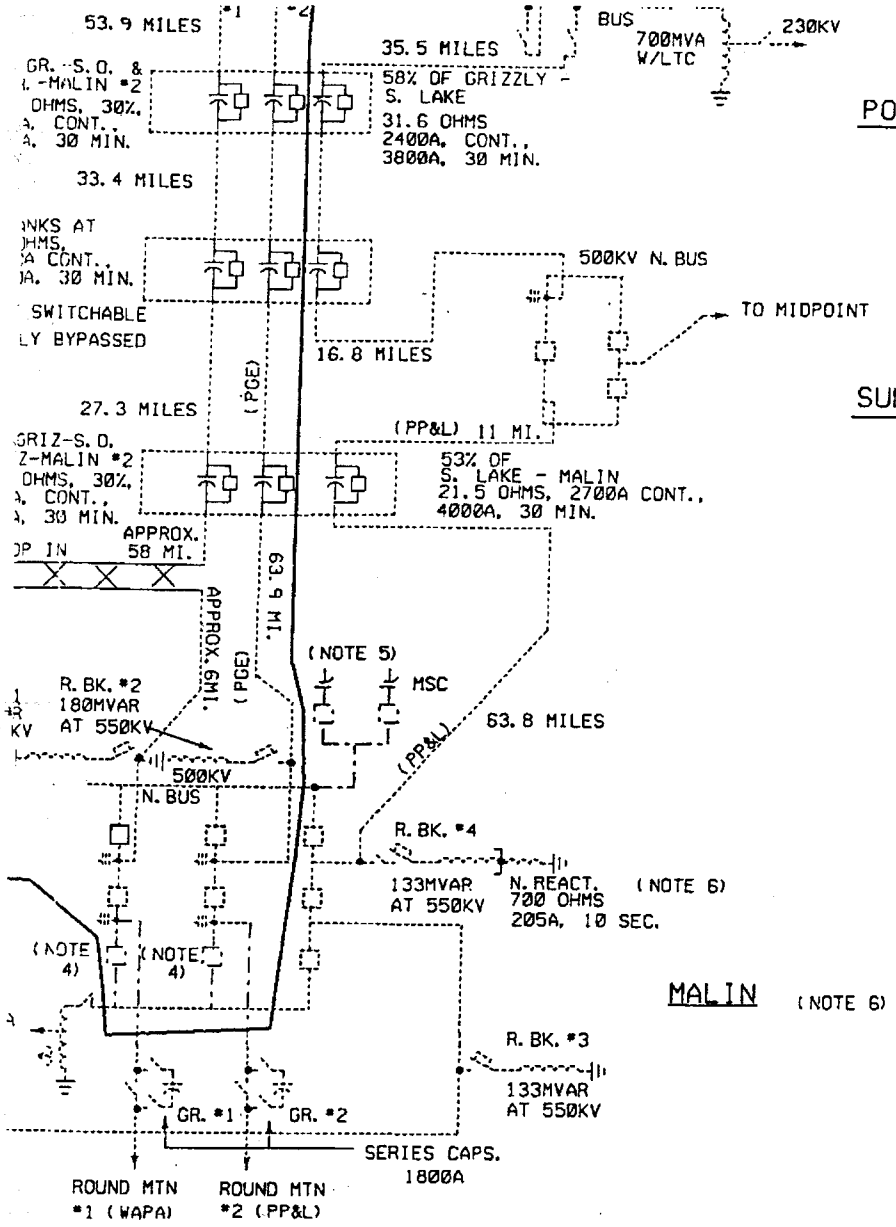
5. MECHANICALLY SWITCHED CAPACITORS (MSC) REQUIRED FOR THE D.C. TERMINAL EXPANSION PROJECT AND BUDGETED UNDER B.I. 150. FY 87.

6. HYBRID SINGLE POLE RELAYING WILL BE INSTALLED BY BPA ON THE J. DAY-GRIZZLY LINES 1 & 2 & THE GRIZZLY-S. OREGON LINE. PGE TO ALSO INSTALL HYBRID SPR ON THE GRIZZLY-MALIN #2 LINE, PROVIDED NO ADDITIONAL SECONDARY ARC EXTINCTION EQUIPMENT IS REQUIRED.

   THE EXISTING FOUR REACTOR SPR SCHEME WILL BE MAINTAINED ON THE GRIZZLY -SUMMER LAKE AND SUMMER LAKE-MALIN CIRCUITS.

7. PGE TO INSTALL A BREAKER IN THE EXISTING BAY 5 WHERE THEIR ROUND BUTTE LINE IS TERMINATED. PGE TO REMOVE EXISTING BREAKER AND BPA TO INSTALL NEW BREAKER IN BAY 4 SOUTH BUS POSITION.


BIG EDDY
500KV YARD
500KV
EAST BUS
TO
500/230KV
TX
CELILO *1
OSTRANDER
CELILO *2
HANFORD
*1
*1
18.9 MILES
*2
500KV
W. BUS
127.6 MILES
TO PEARL
R. BK. *1
180MVAR
AT 550KV
MARION
R. BK. *2
300MVAR
AT 550KV
500KV
S. BUS
*2
*1
99.4 MILES
DBL. CKT.
64.5 MILES
68.97 MILES
LANE
900MVA
TX BK. *3
TO
230KV
YARD
50% MARION-ALVEY
300 MVAR, 2300A,
19.0 OHMS
(NOTE 11)
BK. *5
1008MVA
500/230 KV
AUTO
W/34.5KV
DELTA
TERTIARY
ALVEY
(NOTE 2)
60.7 MILES
16 OHMS
15 MILES
500/230 KV AUTO
W/13.8 KV DELTA
TERTIARY
ROUND BUTTE



THE SERIES CAPACITORS, HOWEVER, WILL NOT OCCUR UNTIL AFTER THE PROJECT ENERGIZATION. UNTIL IT IS DECIDED WHEN TO REMOVE THE CAPACITORS THE STATION WILL OPERATE IN A PERMANENT BYPASSED MODE.

10. THE 2½ INCH ACSR LINE SECTIONS TO BE RECONDUCTORED ALONG THE SLATT-JOHN DAY LINE.

11. SERIES CAPACITORS AT ALVEY, DIXONVILLE AND MERIDIAN ARE REQUIRED FOR THE THIRD AC INTERTIE.

12. ALVEY 500KV SUBSTATION DEVELOPMENT AND ALVEY-SPENCER 500KV LINE SECTION BUDGETED UNDER B.I. 102, EUGENE-MEDFORD 500KV INTERCONNECTION. REFER ALSO TO DRAWING NO. 196480.

13. SOUTHERN OREGON SUBSTATION IS TO BE DESIGNED, OWNED, INSTALLED AND OPERATED BY BPA. PP&L WILL, HOWEVER OWN THE LINE TERMINALS WHERE THEIR MALIN-MERIDIAN LINE TERMINATES, INCLUDING TWO BREAKERS. THE SIX MILES OF LINE FROM S. OREGON TO THE BORDER WILL BE DESIGNED AND INSTALLED BY TANC AT BPA COST BUT OWNED BY BPA.

NO.	COMPUTER REVISION ONLY	COORD ENGR	OM&C	AREA	APPROVED

PROJECT DIAGRAM

FISCAL YEAR PROG.	BUDGET ITEM
87	103

ENERGIZATION DATE(S)
10/91

COORD. ENGR.	CHECKED EOFA
LWM	MAR 6/16/88
CONTROL PD	CHECKED EEP
	LH

OM&C CONCURRENCE
TMS/WLM 6/16/88

AREA CONCURRENCE
EAP 6/16/88 RG 6/16/88

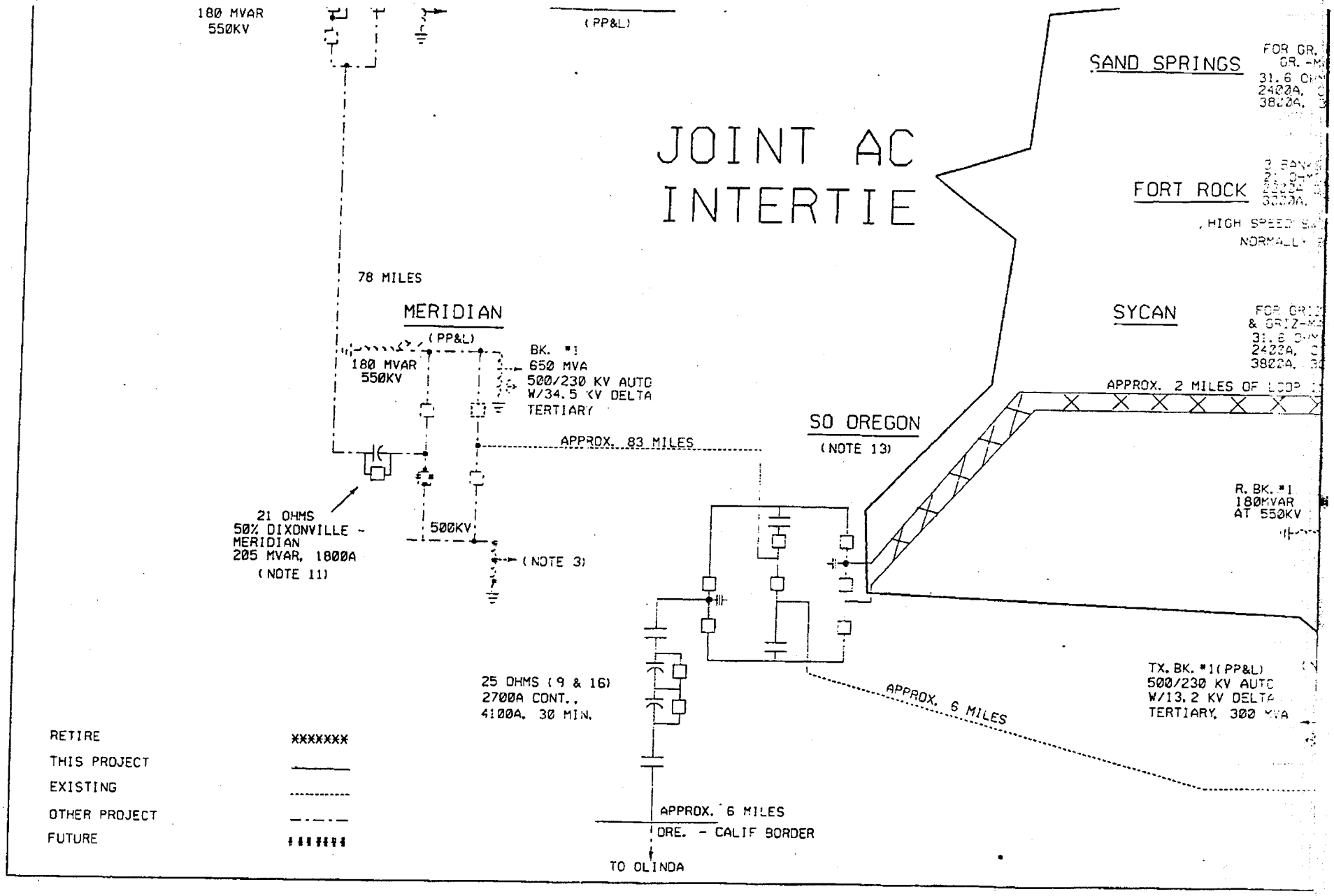
APPROVED
DM PORTER 6/17/88
CHIEF, TRANS. PLANNING BRANCH

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON

DIVISION OF SYSTEM PLANNING

THIRD AC INTERTIE
(NORTHWEST)
EASTERN CORRIDOR OPTION

SERIAL	SOURCE	SIZE	SHEET	REVISION
196486	DSP	A1	01 OF 11	0


JOINT AC INTERTIE
180 MVAR 550KV
(PP&L)
SAND SPRINGS
FORT ROCK
SYCAN
78 MILES
MERIDIAN
(PP&L)
180 MVAR 550KV
BK. #1 650 MVA 500/230 KV AUTO W/34.5 KV DELTA TERTIARY
APPROX. 83 MILES
SO OREGON
(NOTE 13)
APPROX. 2 MILES OF LOOP
R. BK. #1 180MVAR AT 550KV
21 OHMS 50% DIXONVILLE - MERIDIAN 205 MVAR, 1800A (NOTE 11)
500KV
(NOTE 3)
25 OHMS (9 & 16) 2700A CONT., 4100A, 30 MIN.
TX. BK. #1 (PP&L) 500/230 KV AUTO W/13.2 KV DELTA TERTIARY, 300 MVA
APPROX. 6 MILES
APPROX. 6 MILES
ORE. - CALIF BORDER
TO OLINDA
RETIRE
THIS PROJECT
EXISTING
OTHER PROJECT
FUTURE

AC/DC Exchange

Bonneville and Portland hereby agree to exchange a right to use Intertie capability wherein Portland shall have a right to use a share of Bonneville's DC Intertie Rated Transfer Capability and Bonneville shall have a right to use an equal amount of Portland's share of Northwest AC Intertie Rated Transfer Capability under the following terms and conditions. Such exchange shall become effective when the parties execute the necessary agreement containing the terms and conditions as outlined in the memorandums of understanding (MOU) between Portland and Bonneville (Contract No. DE-MS79-88BP92375) and between Bonneville, Portland, and the cities of Burbank, Glendale, and Pasadena, California (Cities) (Contract No. DE-MS79-88BP92376).

1. Term. This Exhibit D shall become effective on the date Bonneville sells power to Portland (Exchange Effective Date) under the terms and provisions of Contract No. DE-MS79-88BP92432, and shall terminate the earlier of (a) 25 years from the date of execution of the Contract No. DE-MS79-88BP92376; or (b) the date of termination of the Intertie Agreement.

2. Extension and Termination of Prior Agreement. Portland and Bonneville's short term letter agreement, Contract No. DE-MS79-87BP92374, providing for the short term exchange of a right to use a share of Bonneville's DC Intertie Rated Transfer Capability for a right to use an equal amount of Portland's share of the AC Intertie Rated Transfer Capability shall be extended by this Exhibit D, and shall terminate on the earlier of 2400 hours on September 15, 1988, or the Exchange Effective Date, however, all liabilities accrued thereunder shall be preserved until satisfied.

3. Ownership. Bonneville shall remain the sole owner of the DC Intertie.

4. Operation and Maintenance of the DC Intertie. Bonneville shall have the sole right and responsibility to operate, maintain, and schedule the DC Intertie in the Pacific Northwest.

5. Exchange of a Right to Use.

(a) Portland shall have a right to use up to 100 MW of Bonneville's DC Intertie Rated Transfer Capability and Bonneville shall have a right to use an equal amount of Portland's share of the Northwest AC Intertie Rated Transfer Capability (Initial Exchange).

(b) Such Initial Exchange may, at Portland's request, be increased by up to 100 MW (Additional Exchange), not to exceed a total of 200 MW when combined with the Initial Exchange, after the DC Terminal Expansion

is declared commercial by Bonneville, if Bonneville has not otherwise contractually committed, or is not in negotiations to contractually commit, the uncommitted DC Intertie Rated Transfer Capability to another use.

(c) Such exchange shall reduce Portland's share of the Northwest AC Intertie Rated Transfer Capability specified in subsections 8(a), (b), and (c) of this Intertie Agreement by the total amount of the exchange.

(d) Bonneville's exchange right to Portland's share of the Northwest AC Intertie shall be subject to paragraph 8(b)(1) of this Intertie Agreement.

6. Transmission Rights on the DC Intertie.

(a) On any hour Portland shall have the right to schedule power and energy up to the amount of the Initial Exchange plus the Additional Exchange to and from the Nevada-Oregon border without regard to the source of the power and energy scheduled. However, Portland's use of the DC Intertie shall be subject to provisions of section 7 of the Long-Term Intertie Access Policy issued by Bonneville on May 17, 1988. Portland shall not wheel for other parties on the DC Intertie. Portland's sales of power or energy at the Nevada-Oregon border are not wheeling under this Agreement.

(b) During times when the DC Intertie Operational Transfer Capability is less than the DC Intertie Rated Transfer Capability, and schedules must be reduced, Portland's right to use of a share of Bonneville's DC Intertie Rated Transfer Capability shall be limited to an amount determined by multiplying the Operational Transfer Capability by the ratio of Portland's right to use share of Bonneville's DC Intertie Rated Transfer Capability to the total DC Intertie Rated Transfer Capability.

(c) Deliveries over the FCRTS to the Big Eddy Substation for the DC Intertie shall be subject to the provisions of subsection 8(d) and 15(c) of this Intertie Agreement.

7. Payment Provisions.

(a) Portland shall pay Bonneville an annual charge of $250,000 for Portland's right to use in the Initial Exchange as defined below.

(b) If Portland acquires an Additional Exchange, the annual charge Portland shall pay to Bonneville shall increase to $1,000,000.

(c) The charges in (a) and (b) above shall be divided into 12 monthly installments and be subject to the billing and payment provisions in Portland's power sales agreement (Contract No. DE-MS79-81BP90425).

8. Losses.

(a) Portland shall be responsible for replacing DC Intertie losses to Bonneville at the Nevada-Oregon border under the provisions of Exhibit G.

(b) Portland shall not be responsible for losses resulting from Bonneville's use of Portland's share of the Northwest AC Intertie Rated Transfer Capability as provided in subsection 14(b) of this Intertie Agreement.

9. Assignment. Portland shall have no rights to sell, assign, lease, sublease, or otherwise transfer any right of use in the DC Intertie. Any such transfer without Bonneville's consent shall be null and void.

10. Waiver of Bonneville's Obligation to Serve Load.

(a) Portland agrees that the disposition of Pacific Northwest energy from Portland's resources for use outside of the Pacific Northwest shall result in a reduction of Bonneville's obligation to supply firm energy under section 5(b) of P.L. 96-501 (16 U.S.C. 839c(b), equal to the maximum amount of energy which Portland is obligated to provide for use outside of the Pacific Northwest for the period of such disposition. Bonneville may sell to Portland as replacement for such energy, under the Power Sales Contract, only what would otherwise be surplus energy. Bonneville shall implement such reduction as described in subsection (b) below.

by PORTLAND

(b) Effective on the date ~~Portland~~ of any sale outside the Pacific Northwest of a resource now dedicated to serve Portland's load in Portland's Power Sales Contract Firm Resource Exhibit, Portland shall submit a revised Firm Resources Exhibit and Assured Capability Exhibit to Bonneville under the Power Sales Contract. The Firm Resource Exhibit shall include, as a Firm Resource, Portland's obligation to provide during each calendar month, an amount of energy equal to the maximum amount of energy Portland is obligated to provide during each such month for use outside of the Pacific Northwest. The determination of Portland's Assured Energy Capability under the Assured Capability Exhibit shall include the monthly amounts of energy from such Firm Resource.

(c) If Portland fails to comply with the terms and conditions of this section, then Bonneville shall have the right to terminate this agreement.

(VS6-PMT-2692d)

Northwest AC Intertie Losses

Portland's 500-kV Grizzly-Malin line will be placed in Bonneville's generation control area and Bonneville shall absorb all losses on the line. Portland shall compensate Bonneville for Northwest AC Intertie losses by making available to Bonneville at points-of-delivery as included in the terms and provisions of Portland's transmission agreements with Bonneville for service over the FCRTS, at the corresponding hour 168 hours later, an amount of electric power calculated as follows:

Given:

Average Northwest AC Intertie losses are 3.0%

Portland can deliver a portion of its schedules through Grizzly Substation, as provided in §8(d)(2), reducing its average loss percentage to 2.5%

For a given hour:

S_{PGE} = Portland's net Northwest AC Intertie schedule, found as the absolute value of the sum of Portland's southbound schedules (positive) and northbound schedules (negative).

L_{PGE} = Portland's loss

Let:

$$L_{PGE} = 0.025 * S_{PGE}$$

This Exhibit E will become effective 90 days after the Effective Date.

The average Northwest AC Intertie loss percentage specified above shall be reviewed annually, and revised as mutually agreed by the parties.

(VS6-PMT-2692d)

Calculation of Charges for Access to Southern Oregon (SO) Substation
1988 ($)

Item No. 1/	Description	2/ Investment	Annual Cost Ratio 3/	Subtotal	O&M Cost 4/	Grand Total
1.	Malin-Meridian Loop into SO 5/	904,000	0.1150	103,960	0 6/	103,960
2.	Grizzly-Malin Loop into SO	4,186,000	0.1150	481,390	3,582	484,972
3.	SO -Or/CA Border	5,265,000	0.1150	605,475	7,164	612,639
4.	SO PCB's, Comm. & Controls 7/	17,621,000	0.1170	2,061,657	282,300	2,343,957
5.	SO Capacitors (10%) 8/	669,000	0.1170	78,273	38,606	116,879
	TOTAL					$3,662,407

PGE Annual Charge = (950 / 4800) * $3,662,407 = $724,852 / YR

1/ BPA's share of Northwest Reinforcement facilities. PP&L's solely owned facilities are not included.
2/ Investment costs include 30% overheads. This column will be revised to reflect actual construction costs.
3/ BPA's Annual Cost Ratio represents recovery of BPA's plant investment costs, revised at time of construction and fixed for the duration of the agreement. When any of the facilities in the table above are replaced or enhanced, PGE shall pay 950/4800 of the associated annual costs, less retirements. Payment schedule for I&A ends, if facilities still exist and are not enchanced or replaced at the end of the service life specified in BPA's Annual Cost Ratio Tables.
4/ BPA's O&M dollars shown for Items 2, 3, 4 and 5 are based on O&M expenses averaged for FY 1985, '86, and '87. O&M charges will be reviewed annually and revised, as appropriate.
5/ BPA's share of the Malin-Meridian Loop-in costs is 50% and PP&L's share is 50%.
6/ PP&L is to operate and maintain the Malin-Meridian Line.
7/ BPA's share is assumed at 6/7th and PP&L's share is 1/7th of $20,558,000.
8/ BPA's share is assumed at 10% and COTP's share is 90% of $6,689,000.

(VS6-PMT-2692d)

Calculation of DC Intertie Losses

The loss factor to be applied to the energy delivered by Bonneville for Portland over the DC Intertie shall be 3.0 percent. Such loss factor shall be reviewed yearly, and revised if appropriate.

(VS6-PMT-2692d)

AUTHENTICATED COPY

Contract No. DE-MS79-91BP93094
7/12/91

INTERTIE TRANSMISSION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

IDAHO POWER COMPANY

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- -

This INTERTIE TRANSMISSION AGREEMENT, executed July 25, 1991, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and IDAHO POWER COMPANY (Company), a corporation of the State of Idaho, hereinafter sometimes referred to individually as "Party" and collectively as "Parties."

W I T N E S S E T H :

WHEREAS Bonneville and the Company, on August 27, 1982, entered into Contract No. DE-MS79-81BP90422, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract"; and

WHEREAS the Company and the Cities of Azusa, California, Banning, California, and Colton, California (Cities), on December 26, 1990, entered into a Power Sale Agreement which, as amended or replaced, is hereinafter referred to as "Sales Agreement"; and

WHEREAS the Sales Agreement provides for the sale of Electric Power by the Company to the Cities; and

WHEREAS Bonneville has developed the LTIAP, which includes provisions for non-Federal access to the Intertie for Assured Delivery to California entities; and

WHEREAS the Company desires transmission service over the Direct Current (DC) Intertie for the transmission of Electric Power to be provided by the Company to the Cities in accordance with the Sales Agreement; and

WHEREAS the Company and Bonneville desire to provide for such DC Intertie transmission service pursuant to the terms of this Agreement and to the terms of the LTIAP; and

WHEREAS the Parties have entered into a General Transmission Agreement, Contract No. DE-MS79-91BP92898 which, as amended or replaced, is hereinafter referred to as "IR Transmission Agreement"; and

WHEREAS Bonneville shall provide for the transmission of Electric Power from a point of integration under the IR Transmission Agreement to the Government's Big Eddy Substation; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto mutually agree as follows:

1. Term of Agreement. This Agreement shall be effective on the Effective Date, and shall continue in effect until the earlier of (1) 20 years from the Effective Date; or (2) the termination date of the Sales Agreement; provided, however, that all liabilities incurred hereunder are hereby preserved until satisfied.

2. Definition and Explanation of Terms.

(a) "Agency" means the Federal Energy Regulatory Commission, or its successor agency.

(b) "Agreement" means this Intertie Transmission Agreement, Contract No. DE-MS79-91BP93094.

(c) "Assured Delivery" is as defined in the LTIAP.

(d) "DC Intertie" means Bonneville's rights in the 1000 kV DC transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to NOB.

(e) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system related to the disturbances of concern, thereby providing acceptable power system performance.

(f) "Effective Date" means the later of (1) 2400 hours on the effective date of the Sales Agreement; (2) 2400 hours on the effective date of the IR Transmission Agreement; or (3) 2400 hours on the date of execution of this Agreement.

(g) "Electric Energy" means electric energy, expressed in kilowatthours.

(h) "Electric Power" or "power" means electric capacity, expressed in kilowatts (kW), or Electric Energy, or both.

(i) "Formula Allocation" is as defined in the LTIAP.

(j) "Intertie" means the DC Intertie and Bonneville's portion of the two 500 kV alternating current (AC) transmission lines from the Government's John Day substation to the California-Oregon border, and associated substation facilities; a portion of the Buckley-Summer Lake 500 kV transmission line and Bonneville's rights in the Summer Lake-Malin 500 kV line; and expansions, improvements, and additions to such transmission lines and substations, including the proposed Northwest Reinforcement Project to the extent such

project is constructed and the third 500 kV AC transmission line interconnecting the Pacific Northwest and California is made operable.

(k) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, attached hereto as Exhibit E.

(l) "Network" means the facilities of the Federal Columbia River Transmission System utilized for the transmission of Electric Power from the Company's transmission system to the Government's Big Eddy Substation.

(m) "NOB" means the Nevada-Oregon border and the point of delivery at such point as described in Exhibit C.

(n) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency or loading condition on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce DC Intertie loadings, whether or not all facilities are in service.

(o) "Pacific Northwest" means the area of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five (75) miles from the area referred to above, which are a part of the service area of a rural electric cooperative customer served by Bonneville on the effective date of Public Law 96-501, which has a distribution system from which it serves both within and without such region.

(p) "Pacific Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act.

(q) "Point of Interconnection" means the Government's Big Eddy Substation, as described in Exhibit C, where Electric Power shall be made available to Bonneville for transmission over the DC Intertie hereunder.

(r) "Prudent Utility Practice" means at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto or, if there are no such practices, methods or acts, the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(s) "Rated Transfer Capability" means the capability of a transmission line or system to transfer Electric Power in a reliable manner as determined in accordance with Prudent Utility Practice.

(t) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville powerflows and/or stability studies.

(u) "Transmission Demand" means the maximum firm DC Intertie transmission capacity, as specified in Exhibit C, for each month, that Bonneville shall be obligated to make available to the Company for transmission of Electric Power under the terms of this Agreement.

(v) "Workday" means each day that Bonneville and the Company jointly observe as a regular workday.

3. Exhibits and Interpretations. The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and

governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement, which represents the entire agreement between the Parties. The headings used in this contract are for convenient reference only, and shall not affect the interpretation of this Agreement. The Company shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. Transmission of Electric Power. Subject to the provisions of this Agreement, the Company shall arrange to make available to Bonneville at the Point of Interconnection, pursuant to the IR Transmission Agreement, the amounts of Electric Power that the Company desires to have transmitted for each hour hereunder, from north to south, over the DC Intertie. Bonneville shall, for each such hour, make equal amounts of Electric Power available for the Company at NOB.

(a) The maximum amount of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand.

(b) The Electric Power transmitted hereunder shall, for the term of this Agreement, reduce the Company's available reserved capacity under Exhibit B of the LTIAP by the amount of the Transmission Demand in this Agreement. The Company shall use its allocation under the LTIAP Formula Allocation methodology for the transmission of the Assured Delivery amount under this Agreement prior to scheduling non-Assured Delivery sales over the Intertie.

(c) During hours when the Rated Transfer Capability of the DC Intertie is reduced due to system conditions, Bonneville shall be obligated to deliver

Electric Power, pursuant to this Agreement, to the extent the Cities and the Company can accept or deliver such Electric Power, up to the Cities' share of reduced Rated Transfer Capability.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints. The amount of curtailment shall be determined consistent with Prudent Utility Practice.

(e) This subsection applies to this Agreement in the event the Company's Transmission Demand, including any shaping under the LTIAP and including transmission demands in other agreements pursuant to which Bonneville provides Intertie transmission to the Company, is equal to or greater than 100 MW. The Company shall, if requested by Bonneville, participate in Intertie Remedial Action Schemes. Bonneville and the Company shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. The Company may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective Control Action is obtained. The level of reliability of the Remedial Action Scheme design on the Company's system shall be at least equal to the level of reliability employed in the design of the overall Intertie Remedial Action Scheme.

(1) The Company's contribution to the total operational responsibility for this scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the Rated Transfer Capability of the Intertie prior to any reduction thereof due to such electrical disturbances.

(2) Bonneville shall provide the appropriate control signal or signals to the Company.

(3) The Company shall provide the necessary equipment to receive and transmit the control signal or signals to the Company's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions.

5. Mitigation Provisions. The Company shall be subject to the operational mitigation provisions of Section 4(d) of the LTIAP as follows:

(a) Condition 1 Provisions.

(1) During hours hereunder when Bonneville has invoked Condition 1 as specified in Section 5(c)(1) or 5(d)(1) of the LTIAP, and the Company's Formula Allocation for such an hour is less than the Company's Assured Delivery, the Company shall purchase the Electric Power difference for delivery to the Cities either from Bonneville, in the event Bonneville has Formula Allocation available for such purpose, or from any other Scheduling Utilities which have Formula Allocation and Electric Power available for such purpose.

(2) The Company shall pay Bonneville each month for the Electric Power purchased by the Company from Bonneville pursuant to (1) above, based upon, at Bonneville's option, (i) Bonneville's standard nonfirm rate, NF-89 or its successor, for sales to California entities, which is determined by Bonneville to best reflect the market conditions in existence on the day Bonneville provides such Electric Power; or (ii) Bonneville's surplus firm rate or at another rate mutually agreed upon by the Company and Bonneville.

(b) Condition 2 Provisions.

(1) During hours hereunder when Bonneville has invoked Condition 2 as specified in Section 5(c)(2) or 5(d)(2) of the LTIAP, and the Company's Formula Allocation for such hours, or for the purposes of Section 5(d)(2) of the LTIAP the Formula Allocation the Company would have otherwise received for such hour if Section 5(c)(2) of the LTIAP were in effect, is less than the Company's Assured Delivery, the Company shall purchase the Electric Power difference from Bonneville, for delivery to the Cities, in the event Bonneville has Formula Allocation available for such purpose.

(2) In the event Bonneville does not have Formula Allocation available for such purpose, the Company may purchase the Electric Power difference from any other Scheduling Utility with available Formula Allocation.

(3) The Company shall pay Bonneville each month for the Electric Power purchased by the Company from Bonneville pursuant to paragraph 5(b)(1) above, based upon, at Bonneville's option, (i) Bonneville's standard nonfirm rate, NF-89 or its successor, for sales to California entities, which is determined by Bonneville to best reflect the market conditions in existence on the day Bonneville provides such Electric Power; or (ii) Bonneville's surplus firm rate or at another rate mutually agreed upon by the Company and Bonneville.

(c) Should Bonneville revise its procedures for administering Operational Mitigation measures included in Assured Delivery contracts entered into pursuant to Exhibit B of the LTIAP, Bonneville agrees to discuss such revisions with the Company. If they so desire, the Parties may amend this

Agreement to prospectively incorporate such revised procedures or such other procedures as may be agreeable to both Parties.

6. Payment Provisions. As compensation for the Intertie transmission services provided to the Company by Bonneville in accordance with section 4 above, the Company shall pay Bonneville each month, in accordance with the provisions of Exhibits B and C, an amount equal to the products obtained by multiplying the Transmission Demand and the amounts of Electric Energy transmitted by Bonneville hereunder by the demand and energy charges, respectively, specified in the Firm Power Transmission Rate included in Transmission Rate Schedule IS-89 (IS-89B rate), or its successor rates. Such amounts of Electric Energy shall be increased by the amount calculated in accordance with the transmission loss factor specified in Exhibit D.

7. Transmission Losses. To compensate Bonneville for Electric Power losses incurred in providing services from the Point of Interconnection to NOB, the Company shall make available, or arrange to have made available, to Bonneville at NOB, unless otherwise mutually agreed upon by the Parties, at the corresponding hour 168 hours later or at another hour agreed upon by the Parties, the amounts of Electric Power determined pursuant to Exhibit D.

8. Power Scheduling. Pursuant to standard scheduling practices, the Company shall submit, or arrange to have submitted, to Bonneville by 0930 hours Pacific Time on each Workday:

(a) A schedule in advance of Electric Power to be supplied to Bonneville for each hour of the following day or days;

(b) A schedule in advance of Electric Power to be supplied to the Company from Bonneville pursuant to section 5 above; and

(c) separate schedules of the hourly amounts of Electric Power to be made available pursuant to section 7 for transmission losses for each hour of the following day or days.

9. Revision of Exhibits.

(a) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of Section 7(i) of the Pacific Northwest Power Act (P.L. 96-501, 16 U.S.C. 839) and Agency rules.

(b) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then-current Intertie operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, that has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with the Company. Losses shall be determined and applied to the Company's transactions under this Agreement in a manner consistent with their application to all similarly situated users of the Intertie having a similar contract with Bonneville as determined by Bonneville. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(c) If Bonneville determines that any charge or parameter specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate, incorporating such revised charges and parameters. Such new exhibit shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(d) Any changes to Exhibit C pursuant to this Agreement shall be upon mutual agreement of the Parties. Upon such mutual agreement, Bonneville shall prepare and issue a revised Exhibit C.

10. Waiver of Bonneville's Energy Service Obligation.

(a) The Company agrees that the disposition of Electric Energy for use outside of the Pacific Northwest pursuant to the Sales Agreement shall result in a reduction of Bonneville's obligation to the Company under section 5(b) of the Northwest Power Act. Bonneville's obligation to supply firm power under the Power Sales Contract, as amended or replaced, shall be reduced on the effective date of a written notice from Bonneville by the maximum amount of Electric Energy which the Company is obligated to provide for use outside of the Pacific Northwest pursuant to the Sales Agreement. Bonneville shall implement such reduction as described in subsection (b) below.

(b) The Company shall submit to Bonneville a revised Firm Resources Exhibit and associated data as specified under the Power Sales Contract effective on the effective date of the notice pursuant to subsection (a) above. The Firm Resources Exhibit shall include, as a Firm Resource, the amount of the Company's obligation to provide Electric Energy for use outside of the Pacific Northwest pursuant to the Sales Agreement.

11. Compliance With Long-Term Intertie Access Policy. Except as otherwise specified in this Agreement, transmission service provided by Bonneville to the Company over the DC Intertie hereunder shall be subject to the terms of the LTIAP. The terms of this Agreement shall not be subject to change upon amendment of the LTIAP, except by mutual agreement of the Parties;

provided, however, Bonneville may unilaterally change the Protected Areas in Exhibit C to the LTIAP to apply such changes to generation resources which have not been licensed by the Agency.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ Walter E. Pollock

By _____
Assistant Administrator
for Power Sales

IDAHO POWER COMPANY

By _____ /s/ J. B. Packwood

Title Vice President Vice President

Date July 16, 1991 July 16, 1991

(VS6-PMT-3405e)

Transmission Parameters

A. Transmission Demand.

7,000 kW

B. Description of NOB and BIG EDDY.

1. NOB POINT OF DELIVERY:

Location: the point in the DC Intertie, near the Nevada-Oregon border, where Bonneville shall make Electric Power available for the Company hereunder;

Voltage: 1000 kV.

2. BIG EDDY POINT OF INTERCONNECTION:

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus;

Voltage: 230 kV and 500 kV.

Transmission Loss Factor

A. Transmission Loss Factor to be Applied to Transmission Pursuant to the Southern Intertie Transmission (IS) Rate Schedule.

Rate Schedule	Loss Factor
IS-89	3.0%

AUTHENTICATED

This Revision No. 2 reduces the Transmission Demand from 4,000 kW to 3,000 kW due to the buyout arrangement of the Power Sales Agreement between Idaho Power Company and the City of Banning, California. The filing of the terms and conditions of this buyout with the Federal Energy Regulatory Commission has been accepted under Docket No. ER98-754-000.

TRANSMISSION PARAMETERS

1. TRANSMISSION DEMAND
3,000 kW

2. POINTS OF DELIVERY AND INTERCONNECTION

a.. Nevada-Oregon Border (NOB) Point of Delivery

Location. The point in the DC Intertie, near the Nevada-Oregon border, where the facilities of the Government and the facilities of the Los Angeles Department of Water and Power interconnect

Voltage. 1000 kV

b. Big Eddy Point of Interconnection

Location. The point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus

Voltage. 230 kV and 500 kV

IDAHO POWER COMPANY

By: /S/ AJAY K. SOOD

Name: Ajay K. Sood

Title: Director, Energy Analysis & Power Transmission

Date: March 4, 1998

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ SUSAN E. GARIFO FURST

Name: Susan E. Garifo Furst

Title: Transmission Account Executive

Date: 12 February 1998

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94280
05/26/94

DC INTERTIE AND NETWORK TRANSMISSION AGREEMENT executed by the UNITED STATES OF AMERICA DEPARTMENT OF ENERGY acting by and through the BONNEVILLE POWER ADMINISTRATION and PACIFICORP

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This DC INTERTIE AND NETWORK TRANSMISSION AGREEMENT, executed June 1, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon (hereinafter referred to individually as "Party" and collectively as "Parties").

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WITNESSETH:

WHEREAS Bonneville and PacifiCorp, on August 27, 1982, entered into Contract No. DE-MS79-81BP90424, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract; and

WHEREAS Bonneville and PacifiCorp have entered into a Letter of Understanding (LOU) dated May 28, 1993, which provides that, among other things, Bonneville shall offer PacifiCorp a firm South-to-North transmission agreement for use of the DC Intertie and Network transmission service associated with PacifiCorp's use of the DC Intertie; and

WHEREAS Bonneville and PacifiCorp entered into an AC Intertie Agreement, Contract No. DE-MS79-94BP94332, which, as amended or replaced, is hereinafter referred to as "AC Intertie Agreement." The AC Intertie Agreement replaced the Intertie Agreement, Contract No. DE-MS79-86BP92299; and

WHEREAS Bonneville desires to provide PacifiCorp DC Intertie transmission service and Network transmission service associated with such DC Intertie transmission service, pursuant to paragraphs 4(a) and (c) of the LOU and the terms of this Agreement; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto mutually agree as follows:

1. **TERM OF AGREEMENT**

This Agreement shall be effective on the Effective Date, and shall continue in effect until termination of the AC Intertie Agreement; provided, however, that all liabilities incurred hereunder are hereby preserved until satisfied.

2. DEFINITION AND EXPLANATION OF TERMS

(a) "AC Intertie" means Bonneville's rights in the following: the two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the ten kilometer (6-mile) 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, improvements, or additions to such facilities.

(b) "Agreement" means this DC Intertie and Network Transmission Agreement, Contract No. DE-MS79-94BP94280.

(c) "Billing Energy" means the monthly sum of scheduled Electric Energy hereunder.

(d) "DC Intertie" means Bonneville's rights in the 1000 kV direct current (DC) transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to NOB.

(e) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system related to the disturbances of concern, thereby providing acceptable power system performance.

(f) "Effective Date" means 2400 hours on the date of execution of this Agreement.

(g) "Electric Energy" means electric energy, expressed in kilowatt-hours.

(h) "Electric Power" or "power" means electric capacity, expressed in kilowatts (kW), or Electric Energy, or both.

(i) "FERC" means the Federal Energy Regulatory Commission, or its successor agency.

(j) "Intertie Transmission Charges" means the Demand Charge and Energy Charge specified in Section II.B. of the Southern Intertie Transmission Rate Schedule (IS) or its successor rate schedules, and included as part of Exhibit B, for DC Intertie transmission service provided hereunder.

(k) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, and amended on April 8, 1993.

(l) "Network" means the facilities of the Federal Columbia River Transmission System utilized hereunder, excluding the AC Intertie and the DC Intertie facilities, for the transmission of Electric Power from the Government's Big Eddy Substation to the Point of Delivery as described in Exhibit C.

(m) "Network Transmission Charge" means the charge specified in Exhibit C and calculated pursuant to the Formula Power Transmission (FPT) Rate Schedule or its successor rate schedules, which is the monthly charge per kilowatt of Transmission Demand for Network transmission service provided hereunder.

(n) "NOB" means the Nevada-Oregon border and the Point of Interconnection as described in Exhibit C.

(o) "Operational Transfer Capability" or "OTC" means the Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, and Operational Constraints, as determined by Bonneville, resulting from, among other things, line or equipment outages, stability limits, or loopflows.

(p) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency, loading condition, or maintenance outage on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce DC Intertie loadings, whether or not all facilities are in service.

(q) "Pacific Northwest" is as defined in the LTIAP.

(r) "Pacific Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act.

(s) "Prudent Utility Practice" means at any particular time, the generally accepted practices, methods, and acts prior thereto in the electrical utility industry in the Western Systems Coordinating Council area or, if there are no such practices, methods or acts, the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(t) "Rated Transfer Capability" or "RTC" means the capability of a transmission line or system to transfer a specified quantity of Electric Power in a prudent and reliable manner.

(u) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville powerflows and/or stability studies.

(v) "Transmission Demand" means the maximum amount of Electric Power that Bonneville shall be obligated to transmit during an hour hereunder. Such amount is specified in Exhibit C and shall be changed only upon mutual agreement of the Parties.

(w) "Workday" means each day that Bonneville and PacifiCorp jointly observe as a regular workday.

3. **EXHIBITS AND INTERPRETATIONS**

The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement. This Agreement sets forth the entire agreement of the Parties as of the date of execution. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement. PacifiCorp shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. **TRANSMISSION OF ELECTRIC POWER**

Subject to the other provisions of this Agreement, Electric Power shall be transmitted on a firm basis from South-to-North, over the DC Intertie from the NOB Point of Interconnection to the Government's Big Eddy Substation (Big Eddy) and over the Network from Big Eddy to the Network Point of Delivery specified in Exhibit C as follows:

(a) The maximum hourly amount of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand.

(b) During hours when the OTC of the DC Intertie is less than the RTC, Bonneville shall deliver Electric Power pursuant to this Agreement to PacifiCorp, to the extent PacifiCorp can accept or deliver such Electric Power, up to PacifiCorp's transmission rights hereunder.

(c) This subsection applies to this Agreement in the event PacifiCorp's Transmission Demand, including transmission demands in other agreements pursuant to which Bonneville provides DC Intertie transmission service to PacifiCorp, is equal to or greater than 100 MW. PacifiCorp shall, if requested by Bonneville, participate in DC Intertie Remedial Action Schemes. Bonneville and PacifiCorp shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. PacifiCorp may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective

Control Action is obtained. The level of reliability of the Remedial Action Scheme design on PacifiCorp's system shall be at least equal to the level of reliability employed in the design of the overall DC Intertie Remedial Action Scheme.

(1) PacifiCorp's contribution to the total operational responsibility for this scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the RTC of the DC Intertie prior to any reduction thereof due to such electrical disturbances.

(2) Bonneville shall provide the appropriate control signal or signals to PacifiCorp.

(3) PacifiCorp shall provide the necessary equipment to receive and transmit the control signal or signals to PacifiCorp's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints, consistent with Prudent Utility Practice, and up to an amount equal to PacifiCorp's transmission rights, such rights to be determined as the amount obtained from the product of the OTC and the ratio of the Transmission Demand to the RTC.

(e) During times when PacifiCorp's transmission rights hereunder are curtailed, Bonneville shall offer available DC Intertie capacity as determined by Bonneville, to PacifiCorp, up to the amount of such curtailment, pursuant to the terms of this Agreement.

5. PAYMENT PROVISIONS

(a) As compensation for the Network transmission services provided hereunder, PacifiCorp shall pay Bonneville in accordance with the provisions of Exhibits B and C for each month, an amount equal to the product obtained by multiplying the Transmission Demand by the Network Transmission Charge specified in Exhibit C.

(b) As compensation for the DC Intertie transmission services provided hereunder, PacifiCorp shall pay Bonneville in accordance with the provisions of Exhibits B and C each month, (1) an amount equal to the product obtained by multiplying the Transmission Demand by the Demand Charge of the Intertie Transmission Charges and (2) the greater of (a) the product obtained by multiplying the Billing Energy by the Energy Charge of the Intertie Transmission Charges or (b) the minimum payment based upon the Energy Charge and a 30 percent load factor. Such minimum energy payment shall be calculated as follows: Transmission Demand (MW) x 8760 hours x Energy Charge (mills/kWh) x .30 ÷ 12.

6. TRANSMISSION LOSSES

To compensate Bonneville for Electric Power losses incurred in providing the services hereunder, PacifiCorp shall schedule and make available to Bonneville on the corresponding hour 168 hours later or on another hour agreed upon at the Network Point of Delivery, the amounts of Electric Power calculated in accordance with the Loss Factors specified in Parts A and B of Exhibit D.

7. POWER SCHEDULING

Pursuant to standard scheduling practices, PacifiCorp shall submit, or arrange to have submitted, to Bonneville by 0930 hours Pacific Time on each Workday or such other time as mutually agreed by the Parties:

(a) A schedule for South-to-North transfers of Electric Power to be made available to Bonneville at NOB for each hour of the following day or days through the next Workday. Changes to such schedules by PacifiCorp shall be accepted up to 30 minutes prior to the hour for which such schedules change is desired; and

(b) a separate schedule of the hourly amounts of Electric Power to be made available pursuant to section 6 for transmission losses for each hour of the following day or days through the next Workday.

(c) Changes to schedules other than those permitted pursuant to 7(a) shall be accepted at any time as mutually agreed by the Parties.

8. REVISION OF EXHIBITS

(a) The initial rate schedules attached hereto as Exhibit B have been confirmed and approved by FERC on an interim basis. If the final rate schedules which are approved by FERC are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated General Transmission Rate Schedule Provisions shall be attached hereto and made a part of this Agreement effective as of the date specified in FERC's approval.

(b) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of Section 7(i) of the Pacific Northwest Power Act and FERC rules.

(c) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then-current AC Intertie and DC Intertie and Network operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, that has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with PacifiCorp. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that any charge specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate, incorporating such revised charges. Such new exhibit

shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(e) If the Parties agree to change Exhibit C pursuant to this Agreement, Bonneville shall prepare and issue a revised Exhibit C.

9. MITIGATION

Pursuant to the Letter of Understanding, dated May 28, 1993, the Parties agree that no LTIAP mitigation shall be applicable under this Agreement, beyond the applicable FERC-approved Bonneville rates.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ SYDNEY D. BERWAGER (acting)
Assistant Administrator
for Power Sales

By ACTING Assistant Administrator for
Power Sales

Name Sydney D. Berwager
(Print/Type)

May 26, 1994

Date 5/26/94

PACIFICORP

By

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date June 1, 1994

/s/ DENNIS P. STEINBERG

Senior Vice President

June 1, 1994

(PMLAN-7664-PMT-W:\PMT\CONTRACT\PPL94280.DOC)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{/(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load-factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

TRANSMISSION PARAMETERS

A. TRANSMISSION DEMAND

(1) 100 MW, effective the later of 0001 hours on January 1, 1994, or 2400 hours on the date of execution of this Agreement.

(2) 200 MW, effective 0001 hours on January 1, 1995.

B. DESCRIPTION OF THE DC INTERTIE POINT OF INTERCONNECTION

NOB:

Location: the point in the DC Intertie, near the Nevada-Oregon border, where Electric Power shall be made available to Bonneville on behalf of PacifiCorp;

Voltage: 1000 kV.

C. DESCRIPTION OF THE BIG EDDY SUBSTATION

BIG EDDY SUBSTATION:

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus;

Voltage: 230 kV and 500 kV.

D. DESCRIPTION OF THE NETWORK POINT OF DELIVERY

BUCKLEY SUBSTATION:

Location: the point in the Government's Buckley Substation at the northern terminus of the Buckley-Summer Lake 500 kV line;

Voltage: 500 kV;

Metering: in the Government's Buckley Substation, in the circuits over which such electric power and energy is delivered.

NETWORK TRANSMISSION CHARGE

E. CALCULATION OF CHARGES PURSUANT TO THE FPT-93.1 RATE SCHEDULE

	Schedule of Annual Charges per kW	Applicable Annual Charges per kW from Big Eddy to Buckley (500 kV)
Facility		
Main Grid		
Interconnection Terminal	$0.27	--
Terminal	$0.44	$0.44
Transmission Distance Charge (1.15 x $0.0371/miles x 44.16 kilometers (27.6 airline miles)	$0.0371/ 1.6 kilometer (1 mile)	$1.18
Miscellaneous Facilities	$1.88	$1.88
Terminal	$0.44	--1/
Interconnection Terminal	$0.27	--
Total Annual Charge $/kW/yr.		$3.50
Transmission Charge $/kW/mo.		$0.29

1/ See Contract No. DE-MS79-79BP90091 and its successor Contract No. DE-MS79-94BP94333 for PacifiCorp's right to use the Government's initial terminal facilities in the Buckley Substation.

TRANSMISSION LOSS FACTORS

A. TRANSMISSION LOSS FACTOR TO BE APPLIED TO TRANSMISSION PURSUANT TO THE FORMULA POWER TRANSMISSION (FPT) RATE SCHEDULE:

Rate Schedule	Loss Factor
FPT-93.1	See Exhibit E, Calculation of Hourly Losses.

B. TRANSMISSION LOSS FACTOR TO BE APPLIED TO TRANSMISSION PURSUANT TO THE SOUTHERN INTERTIE TRANSMISSION (IS) RATE SCHEDULE:

Rate Schedule	Loss Factor
IS-93B	3.0%

CALCULATION OF HOURLY LOSSES

Assume:

Lp = Peak wheeling loss applicable to a specified peak amount of power wheeled under this agreement during the time of peak Federal system generation. Lp is a constant for each hour of a billing period.

Dm = Airline transmission distance plus 15 percent.

Ds = Secondary system transmission distance.

Wm = Maximum power wheeled over main system under this transmission agreement.

Ws = Maximum power wheeled over secondary system under this transmission agreement.

Wt = Maximum power wheeled through the stepdown transformations under this transmission agreement.

Lm = Average loss per megawatt-mile on the main system. Lm is constant for each hour of a billing period.

Ls = Average loss per megawatt-mile on the secondary system. Ls is a constant for each hour of a billing period.

Lt = 230/115 kV transformation loss (percent).

Lt1 = Weighted average of the 115 kV transformation loss (percent).

Lw = Wheeling loss for the power scheduled for a particular hour under this transmission agreement.

Pf = Federal generation for a particular hour.

Pfp = Amount of Federal generation upon which the average wheeling loss, Lm, was based. Pfp is constant for each hour of a billing period.

Pw = Amount of power scheduled for a particular hour to be wheeled under this agreement by Bonneville.

Peak Loss Calculation:

$$\begin{aligned} Lp &= (Dm)(Wm)(Lm) + (Wt)(Lt) + (Ds)(Ws)(Ls) + (Wt)(Lt1) \\ &= (31.74)(100\ MW)(0.143) \\ &= 454\ kW\ per\ MW \end{aligned}$$

Hourly Wheeling Loss Calculation:

$$Lw = \frac{(Lp)(Pf)(Pw)}{(Pfp)(Wm)}$$

$$Let\ K = \frac{Lp}{(Pfp)(Wm)}$$

$$= \frac{454}{(16{,}221{,}000)(100{,}000)}$$

$$= 0.28 \times 10^{-9}/kW = 0.28 \times 10^{-6}/MW$$

Therefore,

$$\begin{aligned} Lw &= K(Pf)(Pw) \\ &= (0.28 \times 10^{-6})\,(Pf)(Pw)/MW \end{aligned}$$

Hourly losses are determined by inserting the amounts of Pf and Pw for a particular hour.

Final Document Certified By:

CCP
94BP94280

Date: 9-30-03
on

Revision No. 4
Exhibit C, Page 1 of 2
Contract No. DE-MS79-

PacifiCorp
Effective as of 0000 Hours

October 1, 2003

AUTHENTICATED

CHARGES, DEMAND, AND POINTS OF DELIVERY

This revision updates the Transmission and Compensation charges with the new Formula Power Transmission Rate Schedule, FPT-04.1, effective October 1, 2003.

A. TRANSMISSION DEMAND

200 MW, effective 0001 hours on January 1, 1995.

B. DESCRIPTION OF THE DC INTERTIE POINT OF INTERCONNECTION

Nevada-Oregon Border

Location: the point in the DC Intertie, near the Nevada-Oregon border, where Electric Power shall be made available to the Bonneville Power Administration (Bonneville) on behalf of PacifiCorp;

Voltage: 1000 kilovolt (kV).

C. DESCRIPTION OF THE BIG EDDY SUBSTATION

Big Eddy Substation

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus;

Voltage: 230 kV and 500 kV.

D. DESCRIPTION OF THE NETWORK POINT OF DELIVERY

Buckley Substation

Location: the point in the Government's Buckley Substation at the northern terminus of the Buckley-Summer Lake 500 kV line;

Voltage: 500 kV;

Metering: in the Government's Buckley Substation, in the circuits over which such Electric Power and energy is delivered.

NETWORK TRANSMISSION CHARGE

E. CALCULATION OF CHARGES PURSUANT TO THE FPT-04.1 RATE SCHEDULE

Facility	Schedule of Annual Charges ($/kilowatt (kW))	Applicable Annual Charges from Big Eddy to Buckley 500 kV ($/kW)
Main Grid		
Interconnection Terminal	0.53	
Terminal	0.59	.59
Transmission Distance Charge (1.15 × 0.0511/mile × 27.6 airline miles)	0.0511/mi.	1.622
Miscellaneous Facilities	2.91	2.91
Terminal	0.59	*/
Interconnection Terminal	0.53	
Total Annual Charge ($/kW/yr)		**5.122**
Transmission Charge ($/kW/mo)		**0.427**

*/ See Contract No. DE-MS79-79BP90091 and its successor Contract No. DE-MS79-94BP94333 for PacifiCorp's right to use the Government's initial terminal facilities in the Buckley Substation.

(W:\TMC\CT\FPT_BILL\94280C4.doc) 09/20/03

Contract No. DE-MS79-94BP94285
05/25/94

AC INTERTIE TRANSMISSION AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP

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This AC INTERTIE TRANSMISSION AGREEMENT, executed June 1, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS Bonneville and PacifiCorp, on August 27, 1982, entered into Contract No. DE-MS79-81BP90424, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract"; and

WHEREAS PacifiCorp and the Western Area Power Administration Sacramento Area Office (Western) have entered into a contract dated September 17, 1992, which, as amended or replaced, is hereinafter referred to as "Western Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to Western; and

WHEREAS PacifiCorp and the City of Redding (Redding) have entered into a contract dated October 19, 1993, which, as amended or replaced, is hereinafter referred to as "Redding Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to the City of Redding; and

WHEREAS Bonneville and PacifiCorp entered into an Intertie Agreement, Contract No. DE-MS79-86BP92299, as amended, effective July 8, 1986, which is hereinafter referred to as " Intertie Agreement", and the Parties have replaced such agreement with Contract No. DE-MS79-94BP94332, which, as amended or replaced, is hereinafter referred to as "AC Intertie Agreement"; and

WHEREAS Bonneville and PacifiCorp have entered into a Letter of Understanding (LOU) dated May 28, 1993, which provides that Bonneville shall under certain circumstances offer PacifiCorp interim and long-term firm transmission contracts providing wheeling for PacifiCorp's Western Sales Agreement and Redding Sales Agreement, and for nonfirm wheeling; and

WHEREAS Bonneville has developed the LTIAP, as defined below, which includes provisions for non-Federal access to the AC Intertie for transactions with Pacific Northwest and California utilities; and

WHEREAS the Parties agree that the terms and conditions of the LOU represent a Joint Venture pursuant to Section 4(b)(1) of the LTIAP; and

WHEREAS consistent with the LOU and in order to facilitate the arrangements provided for in the Western Sales Agreement and the Redding Sales Agreement, Bonneville will provide transmission service in a North-to-South direction from the Points of Interconnection, over the AC Intertie, for deliveries of Electric Power to Western, Redding, and other third parties at the Points of Delivery, and transmission service in a South-to-North direction from the Points of Interconnection, over the AC Intertie, to the Points of Delivery for the delivery of Electric Power to PacifiCorp; and

WHEREAS in accordance with the LOU, Bonneville will provide such access to the AC Intertie for firm and nonfirm transactions up to the Transmission Demand both in a North-to-South and South-to-North direction without regard to the source or ultimate user of services provided under such transactions; and

WHEREAS PacifiCorp and Bonneville desire to provide for such services pursuant to the terms of this Agreement and pursuant to the terms of the LTIAP; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. TERM OF AGREEMENT

This Agreement shall be effective on the Effective Date, and shall continue in effect until the earlier of (1) 2400 hours on December 31, 2018, or (2) the later of the termination date of the Western Sales Agreement or the Redding Sales Agreement. All liabilities incurred under this Agreement are hereby preserved until satisfied. Upon termination of this Agreement, Bonneville will offer to extend such services in an agreement to be executed by the Parties for a period of up to 25 years, based upon Bonneville's then standard terms included in similar agreements, provided that no mitigation charges shall be applied, beyond the applicable FERC-approved Bonneville rates, if PacifiCorp requires such service.

2. DEFINITION AND EXPLANATION OF TERMS

(a) "AC Intertie" means Bonneville's rights in the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line, Bonneville's rights in the Meridian-Malin 500 kV transmission line, Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 10 kilometer 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, improvements, or additions to such facilities.

(b) "Agreement" means this AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285.

(c) "Billing Energy" means the net amount of Electric Energy scheduled in a North-to-South direction and in a South-to-North direction during a month hereunder.

(d) "COB" means the California-Oregon border.

(e) "DC Intertie" means Bonneville's rights in the 1000 kV direct current (DC) transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to the Nevada-Oregon border.

(f) "Demand Charge" means the demand charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(g) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system

related to the disturbances of concern, thereby providing acceptable power system performance.

(h) "Effective Date" means 2400 hours on the date of execution.

(i) "Electric Energy" means electric energy, expressed in kilowatthours.

(j) "Electric Power" or "power" means electric peaking capacity, expressed in kilowatts, Electric Energy, or both.

(k) "Energy Charge" means the energy charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(l) "FCRTS" means the Federal Columbia River Transmission System and other Pacific Northwest facilities over which Bonneville has transmission rights.

(m) "FERC" means the Federal Energy Regulatory Commission, or its successor agency.

(n) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, and amended on April 8, 1993, attached hereto as Exhibit E.

(o) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency, loading condition, or maintenance outage on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce AC Intertie loadings, whether or not all facilities are in service.

(p) "OTC" or "Operational Transfer Capability" means the RTC less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, and Operational Constraints, as determined by Bonneville, resulting from, among other things, line or equipment outages, stability limits, or loopflows.

(q) "Pacific Northwest" is as defined in the LTIAP.

(r) "Points of Delivery" means the points, specified and described in Exhibit C, where Electric Power made available by or on behalf of PacifiCorp shall be delivered by Bonneville.

(s) "Points of Interconnection" means the points, specified and described in Exhibit C, where Electric Power shall be made available by or on behalf of PacifiCorp to Bonneville for transmission over the AC Intertie.

(t) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts existing prior thereto in the electrical utility industry, in the Western Systems Coordinating Council area, or, if there are no such practices, methods, and acts, the practices, methods, and acts, which, in the exercise of reasonable judgment in the light of the facts which were known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(u) "RTC" or "Rated Transfer Capability" means the capability of a transmission line or system to transfer a specified quantity of Electric Power in a prudent and reliable manner.

(v) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville power flows and/or stability studies.

(w) "Transmission Demand" means the maximum amount of Electric Power that Bonneville shall be obligated to transmit during an hour hereunder. Such amount is specified in Exhibit C and shall be changed only upon mutual agreement of the parties.

(x) "Workday" means each day that PacifiCorp and Bonneville jointly observe as a regular workday.

3. EXHIBITS AND INTERPRETATIONS

The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement. This Agreement sets forth the entire agreement of the Parties as of the date of execution. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement. PacifiCorp shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. TRANSMISSION OF ELECTRIC POWER

(a) Subject to the other provisions of this Agreement, Electric Power shall be transmitted by Bonneville on a firm basis from South-to-North and from North-to-South over the AC Intertie, and PacifiCorp shall schedule pursuant to section 7(a) and make available, or arrange to have made available, to Bonneville at the Points of Interconnection the amounts of Electric Power that PacifiCorp determines are available for transmission to the Points of Delivery hereunder for each hour.

(b) The hourly amounts of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand as specified in Exhibit C.

(c) During times when the North-to-South OTC of the AC Intertie is less than the North-to-South RTC, PacifiCorp's reduced net North-to-South scheduling rights shall be an amount determined by multiplying the North-to-South OTC of the AC Intertie by the ratio of PacifiCorp's North-to-South Transmission Demand to the North-to-South RTC of the AC Intertie. During times when the South-to-North OTC of the AC Intertie is less than the South-to-North RTC, PacifiCorp's reduced net South-to-North scheduling rights shall be an amount determined by multiplying the South-to-North

OTC of the AC Intertie by the ratio of PacifiCorp's South-to-North Transmission Demand to the South-to-North RTC of the AC Intertie.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints. The amount of curtailment shall be consistent with Prudent Utility Practice.

(e) PacifiCorp shall be responsible for providing or assuring at its cost the provision of its pro rata share of Remedial Action Schemes required to support the RTC and OTC of the AC Intertie in either the South-to-North or North-to-South direction. Bonneville and PacifiCorp shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. PacifiCorp may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective Control Action is obtained. The level of reliability of the Remedial Action Scheme design on PacifiCorp's system shall be at least equal to the level of reliability employed in the design of the overall AC Intertie Remedial Action Scheme.

(1) PacifiCorp's contribution to the total operational responsibility for this Remedial Action Scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the total RTC of the AC Intertie.

(2) Bonneville shall provide the appropriate control signal or signals to PacifiCorp.

(3) PacifiCorp shall provide the necessary equipment to receive and transmit the control signal or signals to and from PacifiCorp's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions as determined by Bonneville.

(4) In support of its obligations to provide generator dropping for its net North-to-South AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on-line at the time of the Remedial Action Scheme requirement.

(5) Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net North-to-South AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on-line at the time of the Remedial Action Scheme requirement. Such access to PacifiCorp's Mid-Columbia generator dropping capability by Bonneville shall be at no cost to Bonneville.

(6) To the extent that PacifiCorp does not have the capability on-line to provide generator dropping from its Mid-Columbia rights for its net North-to-South AC Intertie schedules, Bonneville shall, to the extent it has available on-line generation, provide generator dropping capability to PacifiCorp at no cost to PacifiCorp.

(7) In support of PacifiCorp's net South-to-North schedules on the AC Intertie, PacifiCorp shall be responsible for making arrangements for any load dropping requirements.

(8) To the extent possible, as determined by Bonneville, Bonneville shall offer to sell Remedial Action Scheme service to PacifiCorp to enable PacifiCorp to meet its obligations under this section 4(e).

(9) Nothing in this section 4(e) shall be construed so as to diminish in any way PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the RTC and the OTC of the AC Intertie in either the North-to-South or South-to-North direction.

(f) When PacifiCorp schedules deliveries pursuant to this Agreement or any agreement for use of AC Intertie capacity entered into pursuant to the LOU, including future Pacific Northwest AC Intertie Capacity Ownership

Agreements, PacifiCorp shall not be required to obtain additional main grid wheeling on Bonneville's system unless insufficient capacity exists in the combined capability of the Midpoint-Malin 500 kV line, the Malin-Meridian Line, and the Alvey-Meridian line for PacifiCorp to use its scheduling rights available to it. If there is insufficient capacity in the combined capability of the Midpoint-Malin line, the Malin-Meridian Line, or the Alvey-Meridian Line, charges will be applied by Bonneville to PacifiCorp consistent with subsection 5(e)(3) of the AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

5. PAYMENT PROVISIONS

(a) As compensation for the AC Intertie transmission services provided hereunder, PacifiCorp shall pay Bonneville, in accordance with the provisions of Exhibits B and C, and as follows:

(1) PacifiCorp shall pay Transmission Demand charges for North-to-South and for South-to-North service, which shall equal the sum of the products obtained by multiplying the North-to-South and the South-to-North Transmission Demands for each month by the Demand Charge; and

(2) PacifiCorp shall pay for energy transmitted hereunder each month, determined as follows:

(A) For North-to-South service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall be the greater of (1) the product obtained by multiplying the North-to-South Billing Energy for each month by the Energy Charge, or (2) a minimum energy payment, based upon the Energy Charge and an 85 percent load factor. Such minimum energy payment shall be calculated as follows: Transmission Demand (MW) x 8760 hours x Energy Charge (m/kWh) x 0.85 ÷ 12; and

(B) For South-to-North service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall equal the product obtained by multiplying the South-to-North Billing Energy for each month by the Energy Charge.

(C) Such payment shall include charges determined by multiplying the amount of hourly losses, calculated in accordance with the transmission loss factor specified in Exhibit D, by the Energy Charge.

6. TRANSMISSION LOSSES

To compensate Bonneville for Electric Power losses incurred in providing the services hereunder, both for deliveries from PacifiCorp and for deliveries to PacifiCorp, PacifiCorp shall schedule and make available to Bonneville on the corresponding hour 168 hours later or on another hour to be agreed upon by the Parties, and at points to be agreed upon by the Parties, the amounts of Electric Power calculated in accordance with the Loss Factors specified in Exhibit D.

7. POWER SCHEDULING

PacifiCorp shall submit, or arrange to have submitted, to Bonneville by 1400 hours Pacific Time on each Workday:

(a) a separate schedule for North-to-South and South-to-North transfers of Electric Power to be made available to Bonneville for each hour of the following day or days through the next Workday. Such North-to-South and South-to-North schedules may be netted against each other. Changes to such schedules by PacifiCorp shall be accepted up to 30 minutes prior to the hour for which such schedule change is desired;

(b) separate schedules of the hourly amounts of Electric Power to be made available pursuant to section 6 for transmission losses for each hour of the following day or days through the next Workday;

(c) changes to schedules other than those permitted pursuant to subsection 7(a) shall be accepted at any time as mutually agreed by the Parties.

8. REVISION OF EXHIBITS

(a) The initial rate schedules attached as Exhibit B have been confirmed and approved by the FERC on an interim basis. The UFT rate schedule has been approved on a final basis. If the final rate schedules which are approved by the FERC are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated General Transmission Rate Schedule Provisions shall be attached hereto and made a part of this Agreement effective as of the date specified in the FERC's approval.

(b) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) and FERC rules.

(c) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then current AC Intertie and DC Intertie operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, which has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with PacifiCorp. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that any charge specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate incorporating such revised charges. Such new exhibit

shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(e) If the Parties agree to any changes to Exhibit C pursuant to this Agreement Bonneville shall prepare and issue a revised Exhibit C.

9. WAIVER OF BONNEVILLE'S ENERGY SERVICE OBLIGATION

(a) PacifiCorp agrees that the disposition of Electric Energy for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement shall result in a reduction of Bonneville's obligation to PacifiCorp under section 5(b) of the Northwest Power Act. Bonneville's obligation to supply firm power under the Power Sales Contract, as amended or replaced, shall be reduced by the maximum amount of Electric Energy which PacifiCorp is obligated to provide for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement. Bonneville shall implement such reduction as described in subsection (b) below.

(b) To carry out the provisions of subsection (a) above, PacifiCorp shall submit to Bonneville a revised Firm Resources Exhibit and associated data as specified under the Power Sales Contract effective on the effective date of the notice pursuant to subsection (a) above. The Firm Resources Exhibit shall include, as a Firm Resource, the amount of PacifiCorp's obligation to provide Electric Energy for use outside of the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement.

10. COMPLIANCE WITH LONG-TERM INTERTIE ACCESS POLICY

Except as otherwise specified in this Agreement, transmission service provided by Bonneville to PacifiCorp over the AC Intertie shall be subject to the terms of the LTIAP. Notwithstanding the terms of the LTIAP, the Parties agree that no mitigation charges shall be applicable under this Agreement. The Parties also agree that the transmission services being provided hereunder are in accordance with Section 4(b) of the LTIAP (New Transactions not subject to Capacity Limits). The

terms of this Agreement shall not be subject to change upon amendment of the LTIAP, except by mutual agreement of the parties; provided, however, Bonneville may change the Protected Areas Exhibit C to the LTIAP and apply such changes prospectively to resources not licensed at the time of the change without the agreement of PacifiCorp. A resource which has been licensed in the past, and for which a new license is pending, shall be considered licensed.

11. PACIFIC NORTHWEST AC INTERTIE CAPACITY OWNERSHIP EXCHANGE RIGHTS

PacifiCorp shall have the right to exchange all or a portion of its AC Intertie firm transmission contract rights acquired under this Agreement with any party receiving Pacific Northwest AC Intertie Capacity Ownership (Capacity Ownership) rights for up to 125 MW of Capacity Ownership rights, to the extent the Capacity Ownership party has rights to assign all or a portion of its Capacity Ownership allocation. To the extent Bonneville has a first right of refusal to acquire Capacity Ownership rights from a Capacity Ownership party, PacifiCorp's exchange rights under this section 11 shall have priority. Such exchange between PacifiCorp and the Capacity Ownership party shall be approved by Bonneville, which approval shall not unreasonably be withheld, and shall ensure that rights, benefits and obligations

to Bonneville under the affected agreements are preserved.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
ACTING *Assistant Administrator for Power Sales*

Name Sydney D. Berwager
(Print/Type)

Date 5/26/94

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date June 1, 1994

(PMTT-8170-W:PMT\CT\PACAD.DOC)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. *Reducing Charges for Interruptions.* If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{/(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Exhibit B

1993

TRANSMISSION RATE SCHEDULES AND

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

Transmission Parameters

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1]

1. North-to-South Transactions:

   a. 01/01/94 to 05/31/94: 75 MW

   b. 06/01/94 and thereafter: 125 MW

2. South-to-North Transactions:

   a. 01/01/94 to 05/31/94: 75 MW x Intertie South-to-North RTC ÷ 4800 MW

   b. 06/01/94 and thereafter: 125 MW x Intertie South-to-North RTC ÷ 4800 MW

[1] Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

Transmission Loss Factors

Transmission Loss Factor to be Applied to Transmission Pursuant to the Southern Intertie Transmission (IS) Rate Schedule

Rate Schedule	Loss Factor
IS-93 B	3.0%

EXECUTIVE SUMMARY

LONG-TERM INTERTIE ACCESS POLICY

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

INTRODUCTION

The Pacific Northwest-Pacific Southwest Intertie began operation in 1968. Congress authorized the construction of the Intertie to provide an additional market for surplus BPA power, thereby providing greater assurance that we would repay the U.S. Treasury for the Federal investments in the Northwest's power system. To the extent there was capacity excess to Federal needs, Congress also intended that the Intertie allow nonfederal utilities in the Northwest and California to take advantage of the diverse load patterns and resource types between the two regions.

The present capability of the Intertie is about 5,200 megawatts (MW), 3,200 MW on the two alternating-current (AC) lines and 2,000 MW on the direct-current (DC) line. Ownership of the Intertie in the Northwest is shared by BPA, Portland General Electric Company (PGE) and Pacific Power & Light Company (PP&L). We provide access to all Northwest generating utilities. Ownership in California is shared by four investor-owned and municipal utilities.

In the early 1980s demand for sales over the Intertie increased dramatically. Nearly every utility in the Northwest had excess power to sell and forecasted a surplus into the next decade and beyond. Northwest utilities frequently filled the Intertie with nonfirm energy and sought to negotiate long-term transactions with California. Prior to 1984 and the implementation of the Interim Intertie Access Policy (IAP), BPA lost significant revenue opportunities by allowing other utilities unfettered access to the Intertie. Combined effects of (1) the Northwest Preference Act, 16 U.S.C. §837, et seq., which gives Northwest utilities a special competitive advantage over us; (2) oversupply conditions in the Northwest; and (3) a restricted market in California due to limited ownership of the Intertie in California caused us to lose sales. We were unable to make our payments to the U.S. Treasury.

In 1984 we implemented the Interim IAP, followed by the Near-Term IAP in 1985. These policies governed access to the Intertie while we developed a Long-Term Intertie Access Policy (LTIAP).

The LTIAP, issued by the Administrator on May 17, 1988, accomplishes the following objectives which have guided us throughout the process:

1. The LTIAP assures BPA of reasonable access to the Intertie to sell both firm and nonfirm energy, thereby enhancing our ability to repay, with interest, $8 billion in Treasury investments.
2. The policy is a reasonable and effective means of safeguarding our $120 million investment in fish and wildlife protection.
3. It balances the competing demands of nonfederal utilities for Intertie access to sell, exchange, or purchase both firm power (through long-term contracts) and nonfirm energy (through the short-term, spot-market).

4. It provides a basis for greater planning certainty to utilities.
5. It allows for efficient use of generating resources in the Northwest and California.
6. It specifically addresses competitive concerns between California and the Northwest.
7. In doing all of the above, it strikes a balance between the Northwest and California, among generating and nongenerating utilities, other BPA customers, environmental interests and Federal taxpayers.

Issuance of this policy culminates our review of comments submitted by over 150 different utilities, regulatory agencies and interest groups. Through a combination of formal, transcribed meetings and informal discussions, we have increased our knowledge of their positions -- and they of ours. We have twice appeared before the U.S. House Subcommittee on Water and Power Resources to answer questions regarding the IAP. Though often cumbersome and lengthy, the process has produced a policy which addresses the demands of all parties.

Balancing interests. We have been put in the difficult position of balancing the competing interests for use of the Intertie. The sum of the demands placed on the Intertie far exceeds the facility's ability to meet them.

Our total-requirements customers insist that BPA should protect its revenues in order to maintain stable power rates and to repay the U.S. Treasury in a timely manner. They suggest that BPA should allocate firm and nonfirm Intertie access to itself first, always assuring that BPA would be able to sell its surplus power. Northwest generating utilities seek a policy which allows sufficient and assured access for their own firm and nonfirm sales. California parties generally argue for a policy which allows them unconstrained access to inexpensive Northwest and Canadian resources. Environmental organizations support a policy that would prevent the Intertie from encouraging development that would harm fish and wildlife resources.

Our main concern in reaching this balanced policy has been reconciling BPA's need to meet its fiscal obligations with these other competing demands for use of the Intertie. While BPA has the discretion to implement the "Federal-first" policy supported by our full requirements customers, the LTIAP instead provides significant access to nonfederal utilities for a variety of transactions while protecting BPA from revenue shortfalls.

It is not reasonable to suggest, as California commenters did in the public process, that BPA incur revenue losses to be recovered through rate increases to its total-requirements customers. These customers have a strong statutory argument -- explained in the decision -- that we should adopt a Federal-first policy to maximize Federal sales over the Intertie. By rejecting Federal-first, we incur an obligation to provide these customers with rate stability through alternative means. First among these alternative protections is the reservation of Intertie capacity for BPA sales.

If the revenue-protective measures adopted in the LTIAP prove unworkable or unduly controversial, the obvious remedy is not more access for nonfederal utilities. Instead, it is Federal-first.

FORMULA ALLOCATION

The Intertie accomodates transactions in two distinct markets. Sellers of power to California sell in two distinct markets, one for long-term transactions and one for short-term sales. Formula Allocation in the LTIAP refers to Intertie capacity made available for short-term sales of energy. We have taken a hard look at Formula Allocations as it has been one of the most hotly debated issues throughout the LTIAP's development.

The LTIAP continues the basic Formula Allocation method used in the Near Term Intertie Access Policy (NTIAP) of allocating access to the Intertie based on three possible conditions. We have changed the specifics of each Condition to reflect criticisms and suggestions made on the two LTIAP drafts. Provisions for Conditions 2 and 3 address directly the contentious anti-competitive concerns between California and the Northwest.

Condition 1. Condition 1 under the NTIAP incorporated the pre-existing Exportable Agreement, which expires on December 31, 1988. Parties to the agreement declare amounts of surplus energy available for export at the applicable BPA rate. If total declarations of exportable energy exceed the available Intertie Capacity or the size of the Pacific Southwest market, whichever is smaller, each party to the agreement is allocated access to the smaller amount based on its share of total declarations.

The 1986 draft LTIAP proposed that upon expiration of the Exportable Agreement a condition of spill or likelihood of spill on the Federal Columbia River Power System (FCRPS) would trigger Condition 1. BPA and Northwest Scheduling Utilities could declare surplus energy available for export and BPA would allocate access to the Intertie based on the ratio of each declaration to the sum of all declarations multiplied by the available Intertie Capacity. Each Scheduling Utility's allocation would be limited by the ratio of its regional hydroelectric capacity to the total regional hydroelectric capacity of the Scheduling Utilities multiplied by the total of all declarations (the "Hydro Cap").

We received comments on the 1986 draft which led us to revise Condition 1 to mirror the Exportable Agreement more closely. Under the 1987 draft a condition of spill or likelihood of spill on the FCRPS determined Condition 1. BPA and Scheduling Utilities could declare surplus energy available for export at the applicable BPA rate and receive a share of available Intertie Capacity based on the Hydro Cap. To the extent that the market for Northwest energy at BPA's price was less than the available Intertie Capacity, we allocated access to the Intertie to equal that market.

Generally, commenters on the 1987 draft did not argue against Condition 1 per se. They focused instead on its specific provisions. The bulk of the comments were directed at the Hydro Cap and at allocating Intertie capacity based on the size of the California market rather than the size of the Intertie capacity. In response to concerns heard at the public meetings in January 1988, we proposed an alternative Condition 1 allocation method. The LTIAP adopts this recent proposal.

The True-Up. The market for power in California is often less than the available Intertie capacity because of minimum generation requirements in California. As the Intertie is expanded and Southwest utilities bring on new generation that cannot be displaced with spot-market purchases, the frequency of this situation is likely to grow.

The 1987 draft allocated Intertie capacity based on the size of the California market as a protection against revenue shortfalls. Analyses indicated that we would lose approximately $16.4 million in 1989 by allocating to the Intertie rather than the market. This loss would decrease to $10.7 million in fiscal year 1992. Beyond 1992 the difference would increase, mainly due to projected fuel price increases.

The heart of the revenue problem is the Northwest Regional Preference Act, 16 U.S.C. 837, et seq., which requires BPA to quote an energy price to Northwest utilities before making any sale to the Southwest. This creates a problem in which Northwest utilities, which are BPA's competitors, know our price -- but we do not know their prices. In Condition 1, where the size of the Southwest market is less than available Intertie Capacity, Northwest utilities are able to use this information to undercut the BPA price and use their allocations to reduce BPA's hourly sales to a small Southwest market. If a "real-time" BPA pricing iteration were even possible, we would still be required to announce our new price to the Northwest. Regional preference makes BPA a "sitting duck" for its competitors.

Allocating according to the California market size would reduce BPA's vulnerability by reducing the size of Scheduling Utility allocations. This provision came under attack, however, from both California and Northwest parties. The alternative discussed at the January 27 public meeting seemed to allay concerns regarding BPA's market control. No one disputes that the Regional Preference Act causes BPA a revenue dilemma, especially at times when we face spill on the hydro system. The true-up alternative is the least intrusive remedy.

The Hydro Cap. Both the 1986 and 1987 LTIAP drafts allocated Intertie capacity based on a utility's hydroelectric capability. The logic for the Hydro Cap was that when the Federal system is spilling or likely to spill, the maximum allocation to utilities with greater hydroelectric resources would increase, thus decreasing the probability of wasting the resources by spilling. Under this provision, BPA's share of allocations would tend to increase due to its large hydroelectric capacity.

Much of the debate over the Hydro Cap focused on two issues. First, removing the Hydro Cap could cause hydro-based utilities to spill. Second, without the Hydro Cap, utilities could "overdeclare" by including uneconomic combustion turbines in their declarations with no intent of ever operating them.

Discussion at the January meetings helped resolve these concerns. When the Federal hydro system faces spill, other systems might not always be in the

same condition. The Hydro Cap could give disproportionately large shares of Intertie Capacity to hydro-based utilities when they may not face a threat of spill, while frustrating the marketing activities of utilities with hydro and thermal resources. Furthermore, several utilities and BPA indicated that if a utility is facing spill with insufficient access to market the available energy on the Intertie, such energy could generally displace Northwest thermal generation.

Several factors would help deter overdeclarations. First, the take-or-pay feature of our IS-87 transmission rate requires a utility to pay for its allocation whether or not it is used. Second, BPA monitors declarations and is aware of each utility's resources and capabilities. We have not observed significant overdeclarations under past policies. Third, from time to time we can request documentation on each utility's declaration as a further insurance against abuse.

Conditions 2 and 3. Allegations of anti-competitive practices on both the northern and southern portions of the Intertie were made during the debate over Formula Allocations. California commenters argue that pro-rata allocations to nonfederal utilities under the LTIAP would tend to stabilize prices at levels higher than those at which sellers might increase their total sales by reducing prices. The Northwest just as logically concludes that pro-rata allocations of California Intertie capacity suppress prices below levels that would prevail in a market where more buyers independently bid for Northwest energy.

We recognized that in implementing a long-term policy we must try to resolve this issue to meet the goals outlined for the LTIAP. We therefore proposed in section 5(d) of the 1987 draft LTIAP to cease pro-rata allocations to non-Federal utilities under Conditions 2 and 3 after completion of the third AC Intertie, provided anti-competitive problems in the Southwest were cured by that time. This proposal was discussed extensively during the public meetings in January 1988 and again in comment letters, mainly from California parties. The final LTIAP takes this proposal a step further. Section 5(d) now ceases pro-rata allocations under Conditions 2 and 3 for an 18-month experimental period.

We will analyze the success or failure of the experiment throughout its term. We will be particularly concerned about the removal of restrictions on California's portion of the Intertie. Utilities, regulators, and other interested parties will be encouraged to express their views in writing and through informal discussions. At least 30 days before the experiment ends, we will issue a written report on whether to continue the experiment.

The experiment will work as follows. Under Condition 2, when the declarations of BPA and Northwest utilities exceed Intertie capacity, we will make a pro-rata allocation to BPA and leave the remaining block of Intertie capacity available to Northwest utilities as a whole. Each Northwest utility could then compete to make sales to Southwest utilities, with no assurance of any individual allocation. Under Condition 3, when the declarations of BPA

and Northwest utilities are less than Intertie capacity, BPA will receive an allocation equal to its declaration and Northwest utilities will receive a block allocation equal to the sum of their declarations. After regional utilities, U.S. extraregional utilities and then Canada have access to remaining Intertie capacity. During Condition 3, we expect significant competition whenever the size of the California market is less than Intertie capacity.

Until the experiment is in effect, Conditions 2 and 3 are similar to those in the NTIAP and the two LTIAP drafts.

The LTIAP retains pro-rata allocations under Condition 1. Allocation under Condition 1 appears to be of less concern to California commenters than allocation during other conditions. Alternative Formula Allocation proposals recognized the importance of pro-rata allocations when the Northwest faces spill conditions. Retention of Condition 1 allocations will (1) help assure nonfederal utilities of Intertie access when hydrological conditions might otherwise force them to spill, and (2) provide an enforcement mechanism for the Protected Area provisions described below.

Some commenters have suggested that we allow access to Canadian utilities equal to that of Northwest utilities. The courts, however, have upheld our policy that capacity excess to our needs must be provided on a fair and nondiscriminatory basis first to Northwest utilities. If the Free Trade Agreement between Canada and the United States now being considered in Congress and the Canadian parliament is implemented, the distinction between U.S. extraregional utilities and Canadian utilities will no longer be made.

ASSURED DELIVERY

Utilities seek firm access to the Intertie for long-term transactions. The LTIAP refers to this kind of access as Assured Delivery. The earlier NTIAP did not provide for Assured Delivery service.

Amount. The final LTIAP reserves 800 MW for Assured Delivery transactions. This is an increase from the 420 MW reserved in the 1986 draft. BPA lost $213 million in fiscal year 1987; we do not want to exacerbate this problem with the final LTIAP. Given these uncertainties, we are cautious about committing major portions of the Intertie for long-term nonfederal use.

Yet, the 800 MW upper limit in itself is a fairly dramatic departure from the past. It will facilitate a greater number and variety of firm transactions than before. Our studies indicate an annual revenue loss of approximately $9 million in lost nonfirm revenue and displaced firm power sales to our public agency customers. The revenue effects on BPA have been quantified further in a study by the PNUCC. These adverse revenue effects, offset by mitigation measures discussed below, have been found acceptable by a fairly broad cross-section of commenters.

In the public meeting and comment letters, most parties seemed satisfied with the 800 MW if we were to consider increasing it upon completion of the third AC project. BPA will reassess the 800 MW limit upon commercial operation or termination of the project.

Exhibit B Allocations. As for the limits on types of transactions, BPA is convinced of the wisdom of imposing limitations on firm power sales. These limits are shown in Exhibit B of the LTIAP. From the standpoints of environmental quality and financial risks, it seems appropriate to limit Assured Delivery capacity to the amount of firm surplus presently available in the Northwest for export sales. In a change from the 1987 draft policy, the LTIAP provides that Scheduling Utilities may use their individual Exhibit B amounts for sales or exchanges.

The final LTIAP does not allocate the remaining 356 MW of Assured Delivery capacity among Scheduling Utilities. That amount will be available for exchange transactions of Scheduling Utilities on a first-come, first-served basis.

We have reached agreement (or agreement in principle) covering 341 MW of Assured Delivery service. Agreements include a 20-year 105 MW firm power sale from Montana Power Company to Los Angeles Department of Water and Power; a 41 MW firm power sale from Tacoma City Light to Western Area Power Administration (WAPA); a 45 MW firm power sale from Longview Fibre/Cowlitz County Public Utility District to WAPA; and a 20-year 150 MW seasonal exchange between The Washington Water Power Company and Pacific Gas and Electric Company. Each of these agreements accommodates our lost revenue concerns differently.

To allow for maximum use of the Intertie, a utility granted Assured Delivery may shape its firm power sale into the months of September through December by delivering up to 1.8 times its Exhibit B amount. During those fall months, spot market energy sales to the Southwest tend to be less than in the spring when the region's hydroelectric dams are more often near or in a spilling condition. If a utility shapes Assured Delivery energy into the fall, less firm energy may be shaped into remaining months of the operating year so that the total energy delivered does not exceed its annual Exhibit B energy maximum for firm sales.

BPA will also continue to work with Nonscheduling Utilities to provide the opportunity to sell the output of their generating resources over BPA's Intertie capacity.

Mitigation. Mitigation refers to conditions imposed on a utility for an Assured Delivery contract. Intertie Capacity not available to BPA because of Assured Delivery contracts executed between a Northwest utility and a Southwest utility can reduce BPA revenues and inhibit BPA's ability to make its Treasury payments. During the operating year BPA often has power available to fully load the Intertie. Assured Delivery granted under these circumstances would reduce BPA's revenues, thereby putting at risk our ability to meet our obligations to the Treasury.

This fiscal concern is in potential conflict with the policy objective underlying the 800 MW of Assured Delivery -- assisting Northwest utilities in disposing of their surpluses by means of long-term firm power sales to the Southwest. Strong objection was received from our Priority Firm Power customers to our absorbing the entire cost (lost revenues) of these transactions and the subsequent passing of the costs to them in increased rates. California and Northwest generating utilities generally tend to agree that some form of mitigation is due BPA. They question the level of compensation and what provisions for mitigation should be included in the LTIAP.

The 1986 draft of the LTIAP allowed Assured Delivery without regard to the adverse impacts on BPA's ability to sell firm power or nonfirm energy. Both the 1987 draft and the LTIAP impose mitigation upon utilities with Assured Delivery contracts. The mitigation provisions in the LTIAP provide only partial compensation for the revenue impacts resulting from transactions, but provide sufficient assurance that these transactions over the Intertie will not harm our revenue recovery.

It would be a false precision to claim that we could develop mitigation measures that offset dollar-for-dollar the losses projected in any 20-year study. Assumptions about annual rainfall, gas prices, aluminum prices, and load growth make this exercise judgmental. With this limitation in mind, the LTIAP incorporates the following mitigation provisions.

One mitigation measure requires that during any hour in which prescheduled energy sales are made under Condition 1 and Condition 2 Formula Allocation

procedures, a utility must deduct its Assured Delivery amount from its Formula Allocation amount. The total amount of Intertie access granted to each utility is equal to its Formula Allocation. If a utility's Assured Delivery amount is greater than its Formula Allocation, then that utility must purchase enough energy from BPA or, during Condition 1, other Northwest utilities to make up the difference. This mitigation measure will partially offset the spot-market revenues BPA will lose by granting Assured Delivery.

Under the other mitigation measure, if BPA has invoked Condition 1 or Condition 2 Formula Allocations, cash out provisions of exchange contracts become inoperative. Cash outs allow a Northwest utility to accept dollar payments from a Southwest utility in lieu of actual energy returns. Prohibiting these during Conditions 1 and 2 has the effect of increasing the north-to-south capability of the Intertie when energy is being returned and increasing the size of the market for BPA and Scheduling Utility sales.

The draft LTIAP required energy returns under seasonal exchanges to the California/Oregon border (COB) or the Nevada/Oregon border (NOB). This was initially included in the mitigation provisions for seasonal exchanges. However, BPA needs the certainty of available capacity resulting from return requirements at COB/NOB. For this reason, the final LTIAP includes this provision as a standard requirement for all exchanges rather than considering it a mitigation measure.

The LTIAP also allows utilities the opportunity to negotiate individual packages of mitigation in addition to the LTIAP's stated mitigation provisions. Such case-by-case mitigation packages could be a combination of the above mitigation provisions or could include beneficial arrangements for BPA that have not been addressed in this policy. Our main concern in any mitigation package is recovery of any spot-market revenue losses, but we will also be looking at the operational impacts of any proposal.

Extraregional Access. Provisions in the 1987 draft for firm transactions by extraregional utilities required that the utility must provide some benefit to BPA, such as increased storage, improved system coordination or operation, or other consideration of value. In addition, the utility must agree to the mitigation provisions of the policy. Canadian utilities were required to wait for access until after the Intertie was rated at 7900 MW.

In reconsidering this provision we saw no reason for denying Canadian utilities access for firm transactions until after the Intertie is upgraded to 7900 MW if Canadian utilities are willing to provide increased coordination or other items of value. This provision of limiting Canadian access to after an upgrade of the Intertie has been deleted from the LTIAP.

As with Formula Allocation, BPA anticipates that if the Free Trade Agreement is passed the distinction between U.S. extraregional utilities and Canadian utilities will no longer exist.

FISH AND WILDLIFE PROTECTION

Protected Areas. The LTIAP prohibits Intertie access for new hydro projects licensed within "protected areas" -- river reaches withdrawn from hydro development due to the presence of wildlife or anadromous and high-value resident fish. BPA also has designated areas where we have determined that investments in habitat, hatchery, passage, or other projects may result in the presence of anadromous fish. The Northwest Power Planning Council (Council) has proposed a protected area program that covers the entire Northwest. BPA's designations, however, cover only the Columbia River basin.

Our focus is on hydro developments which will frustrate our investments made in the region to achieve the goals of the Council's Fish and Wildlife Program. The LTIAP ensures that those expenditures and existing productive habitat will not be harmed by future hydro developments. BPA has designated protected areas by using information collected through the Council's Hydro Assessment Study.

Under the LTIAP, we will consider the Council's final protected area program or any revisions the Council may include in the future. We will also consider appropriate state comprehensive river plans. The policy should effectively eliminate utilities' fears that they never know with certainty whether a hydro resource will qualify, or continue to qualify, for access to the Intertie.

The LTIAP does not necessarily prevent hydro development in protected areas. However, the protected area provisions will send an unambiguous, self-enforcing message to FERC, other regulators, and hydro developers that no Intertie access will be provided for projects constructed in areas of greatest concern to BPA and the Council.

Enforcement. If a Scheduling Utility proceeds to acquire a license or purchase power from a hydro project developed in a protected area, BPA will reduce the amount of that utility's power transmitted over the Intertie during Condition 1. Depending upon the size of the project, the reduction may affect both Assured Delivery and Formula Allocations. These reductions will take place regardless of whether power from the protected area project is actually transmitted on the Intertie. There is no need to trace power flows from a protected area resource.

Projects not affected by the Policy. For all hydro projects not affected by BPA's protected area designations, BPA will intervene in FERC proceedings if we determine that projects -- new or existing, inside or outside the Columbia Basin -- pose significant threats to our fish and wildlife responsibilities.

The provisions do not affect hydro projects licensed before the effective date of the policy. While we recognize a potential for existing projects to harm BPA fish and wildlife investments, we do not believe there is sufficient evidence to indicate that those projects are presently operating contrary to

the Council's Fish and Wildlife Program or that the Council has been unable or unwilling to implement Program measures through the FERC process. Measures affecting existing projects in the Council's Program are explicitly directed to FERC and state agencies for implementation.

We have provided a limited procedure to provide access to the Intertie in the case of a project a developer believes will contribute to the Council's Fish and Wildlife Program and BPA investments. However, our decision to provide access relies on a clear demonstration of the benefits and a regional consensus.

Finally, the LTIAP creates a limited exception for Protected Area projects that an investor-owned utility might be forced to acquire under PURPA. To qualify, however, the affected utility must pursue all legal remedies available to avoid purchasing the Protected Area project output.

LONG-TERM INTERTIE ACCESS POLICY

GOVERNING TRANSACTIONS OVER FEDERALLY OWNED
PORTIONS OF THE
PACIFIC NORTHWEST-PACIFIC SOUTHWEST INTERTIE

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

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FINAL LONG-TERM INTERTIE ACCESS POLICY

Section 1. **Definitions**

1. "Administrator" means the Administrator of Bonneville Power Administration (BPA) and is used interchangeably with BPA.

2. "Administrator's Power Marketing Program" refers to all marketing actions taken and policies developed to fulfill BPA's statutory obligations. These actions and policies are based on exercises of authority to act, consistent with sound business principles, to recover revenue adequate to amortize investments in the Federal Columbia River power and transmission systems, while encouraging diversified use of electric power at the lowest practical rates. In the Northwest, the Administrator's Power Marketing Program covers BPA's obligations to provide an adequate, reliable, economical, efficient, and environmentally acceptable power supply, while preserving public preference to Federal power. In the Southwest, the Administrator's Power Marketing Program covers activities to market surplus Federal power at equitable prices, while preserving regional and public preference to Federal power, and to assist in marketing Northwest nonfederal power.

3. "Allocation" means the share of the Intertie Capacity made available for short-term sales of energy.

4. "Assured Delivery" means firm transmission service provided by BPA under a transmission contract to wheel power covered by a contract between a Scheduling Utility and a Southwest utility. Assured Delivery contracts may not exceed 20 years in duration. The service is interruptible only in the event of an uncontrollable force or a determination made pursuant to sections 7 or 8 of this policy.

5. "Available Intertie Capacity" is defined as the physically available capacity controlled by BPA, reduced by the capacity reserved under Section 2 of this policy, and the capacity necessary to satisfy Assured Delivery contracts not subject to operational mitigation requirements under this policy.

6. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts; and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act.

7. "Exchange" refers to various types of transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power, at prespecified delivery rates, from North to South during the Southwest's peak demands and returns of capacity and/or energy from South to North during other times. Transactions vary depending on the lag between deliveries and returns. A "naked capacity" transaction might require off-peak energy returns within 24 hours, whereas a seasonal exchange might call for firm power returns within 6 months.

8. "Extraregional Utilities" are generating utilities, or divisions thereof, that do not provide retail electric service and do not own or operate significant amounts of generating capacity in the Northwest.

9. "Formula Allocation" means the process by which Intertie Capacity made available for short-term sales of energy.

10. "Intertie" means the two 500-kv alternating current (AC) transmission lines and one 1000 kv direct current (DC) line, which extend from Oregon into California or Nevada, and any additions thereto identified by BPA as Pacific Northwest-Pacific Southwest Intertie facilities.

11. "Intertie Capacity" means the North to South transmission capacity of the Intertie controlled by BPA through ownership or contract; increased by power scheduled South to North, decreased by loop flow, outages, and other factors that reduce transmission capacity; and further decreased by Pacific Power & Light Company's schedules, under its scheduling rights at the Malin substation (BPA Contract Nos. DE-MS79-86BP92299 and DE-MS79-79BP90091).

12. "Mitigation" refers to the requirements imposed by BPA on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's firm power transaction, that inhibit BPA's ability to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless a scheduling utility either agrees to a specially designed charge or negotiates substitute measures with BPA on a case-by-case basis.

13. "Nonscheduling Utility" means a nonfederal Northwest utility that owns a Qualified Northwest Resource, but does not operate a generation control area within the Pacific Northwest. A Nonscheduling Utility requesting Intertie access for its resource must do so through the Scheduling Utility (or BPA) in whose control area the resource is located.

14. "Pacific Northwest" (or "Northwest") is defined in the Northwest Power Act, 16 U.S.C. §839e, as the states of Oregon, Washington, and Idaho; the portion of Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and any contiguous service territories of rural electric cooperatives serving inside and outside the Pacific Northwest, not more than 75 air miles from the areas referred to above, that were served by BPA as of December 1, 1980.

15. "Protected Area" means a stream reach within the Columbia River drainage basin specially protected from hydroelectric development because of the presence of anadromous or high value resident fish, or wildlife. Protected areas may also include stream reaches which could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

16. "Qualified Extraregional Resource" means:

(a) a generating unit located outside the Northwest that was in commercial operation on the effective date of this policy. However, the term excludes portions of units covered as Qualified Northwest Resources.

(b) after BPA has determined that the capacity of the Intertie is rated at approximately 7,900 MW, all resources located outside of the Northwest, other than the portions of extraregional resources covered as Qualified Northwest Resources.

17. "Qualified Northwest Resource" excludes BPA Resources, but includes:

(a) Resources located inside the Northwest that are in commercial operation as of the effective date of this policy.

(b) Scheduling Utility extraregional generating resources dedicated to Northwest loads on the effective date of this policy. This term includes pro rata portions of Montana Power Company's and Pacific Power and Light Company's shares of the Colstrip No. 4 generating station, based on the ratio of their respective regional loads to their respective total loads; and Idaho Power Company's share of Valmy No. 2.

(c) New regional resources of Scheduling Utilities, except for hydroelectric resources located in Protected Areas.

18. "Resource" means an electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

19. "Scheduling Utility" means the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The term excludes Utah Power & Light Company, either as a separately owned company or as a division of another corporation, which has sufficient transmission capacity to the Southwest without access to the Federal Intertie.

20. "Seasonal Exchange" means a transaction that takes advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power, at a prespecified delivery rate, from North to South during the Southwest's summer load season and from South to North during the Northwest's winter load season. Seasonal Exchanges may involve payments of additional consideration to reflect the relative seasonal values of power throughout the western United States. Seasonal Exchange schedules of Northwest utilities will be referred to as "deliveries," and schedules of Southwest utilities will be referenced as "returns." A Scheduling Utility must be able to support its summertime firm power deliveries with generating resources that are surplus to its Northwest requirements. The sum of a Scheduling Utility's energy resources for each month in which deliveries are made (with special concern for August) must exceed its corresponding Northwest loads by an amount sufficient to support the Seasonal Exchange.

21. "Section 9(i)(3) resource" means a Scheduling Utility resource that BPA has granted priority in receiving BPA transmission, storage and load factoring services as defined in §9(i)(3) of the Northwest Power Act.

Section 2. **Intertie Capacity Reserved for BPA**

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) transmit all of BPA's surplus firm power and to serve other obligations,

(b) perform obligations, including, but not limited to, the existing transmission contracts listed in Exhibit A, to the extent such obligations differ from the conditions specified in this policy,

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit B to this policy, and

(d) satisfy BPA firm obligations, that have not been prescheduled, by using unutilized portions of Formula Allocation amounts.

Section 3. **Conditions For Intertie Access**

(a) All Intertie access will be granted pursuant to the conditions and procedures of this policy, unless otherwise specified in the three existing BPA transmission contracts listed in Exhibit A.

(b) BPA will provide Intertie access only for BPA Resources and the Qualified Northwest Resources of Scheduling Utilities, except to the extent that Qualified Extraregional Resources are permitted access under this policy.

(c) BPA will provide Assured Delivery and allocate remaining Intertie Capacity when providing such access will not substantially interfere with operating limitations of the Federal system. Examples of these limitations, which reflect BPA's obligation to operate in an economical and reliable manner consistent with prudent utility practices, include:

(1) The BPA Reliability Criteria and Standards,
(2) Western Systems Coordinating Council minimum operating reliability criteria,
(3) North American Electric Reliability Council Operating Committee minimum criteria for operating reliability, and
(4) coordination agreements among BPA, scheduling utilities and other Federal agencies regarding resource and river operations.

(d) Any utility that has contractual or ownership rights to Pacific Northwest-Pacific Southwest Intertie capacity or to other transmission lines to California or the Southwest market must fully utilize such capacity prior to receiving any access to BPA's Intertie Capacity. If a Scheduling Utility with Intertie rights needs BPA Intertie Capacity to reach a particular Southwest utility, BPA will consider negotiated swaps of capacity to accommodate such requests.

Section 4. **Assured Delivery for Intertie Access**

Subject to the limitations and other conditions in this section and in other sections of this policy, BPA has determined that it can provide limited Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) **General Provisions**

(1) **Existing Transmission Contracts.** BPA will provide Assured Delivery for the remaining terms of the firm power sale and Seasonal Exchange contracts identified in Exhibit A to this policy.

(2) **Utilities Owning Or Controlling Southwest Interconnections.** Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. Except for transactions covered by section 4(b) of this policy, a utility with capacity on an intertie, through contract or ownership, must utilize all such capacity on a firm basis before receiving any Assured Delivery.

(3) **Nature Of Transactions.** BPA will not provide Assured Delivery for transactions which a Scheduling Utility cannot demonstrate to be other than an advance arrangement to sell nonfirm energy.

(4) **Waiver Of BPA Service Obligation.**

(A) **Hydroelectric Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest hydroelectric energy shall provide, under 16 U.S.C. §837b(d), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided .

(B) **Thermal Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest thermal energy shall provide, under 16 U.S.C. §839f(c), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided. Such reduction shall become effective at the time BPA determines that it has reached energy load/resource balance, or at a date as specified in the Assured Delivery contract.

(5) **Exchange Contracts.** Exchange contracts must specify that all return energy be scheduled to either the AC Intertie point of interconnection at the California-Oregon border ("COB") or the DC Intertie point of interconnection at the Nevada-Oregon border ("NOB"). Exchange contracts must also specify prescheduled determinations of hourly energy returns.

(6) **Satisfying Requests For Assured Delivery.** All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made.

(b) **New Transactions Not Subject To Capacity Limits**

(1) **Joint Ventures.** Joint ventures between BPA and utilities, such as firm displacement contracts, which allow BPA to increase its sales of surplus power qualify for Assured Delivery.

(2) **Sales In Lieu Of Exchanges.** BPA may offer to satisfy Scheduling Utility demands for Seasonal Exchanges by selling them incremental amounts of surplus firm power during winter months. Upon committing to purchase such incremental firm power at negotiated prices that reflect BPA's

lost opportunities for summer sales, a Scheduling Utility will qualify for Assured Delivery (with mitigation) to wheel an equal amount of firm capacity and energy over the Intertie during summer months.

(3) **Conditions**. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(b)(1) and 4(b)(2). Relevant contracts must be presented for review when Assured Delivery is requested. BPA will satisfy a request within 60 days after a Scheduling Utility has demonstrated satisfaction of the requirements of this policy.

(c) **Transactions Subject To Capacity Limits Under This Policy**

(1) **Maximum Amounts Of Assured Delivery**. BPA will provide 800 MW of Assured Delivery for firm power sales and Exchanges identified in this policy. BPA will reassess the amount of Assured Delivery capacity when the 3d AC Intertie project is either completed or abandoned. Moreover, the 800 MW amount may be subject to some reduction if the DC Terminal Expansion project is not completed on schedule.

(2) **Exhibit B amounts**.

(A) **Current maximum**. Each Scheduling Utility's maximum Assured Delivery amount for firm sales equals its average firm energy surplus, shown in Exhibit B to this policy. BPA will reserve capacity equal to each Scheduling Utility's Exhibit B allocation subject to section 4(c)(2)(D) below. Except for Montana Power Company (MPC), Tacoma City Light, and Cowlitz County Public Utility District, Exhibit B represents projected Scheduling Utility surpluses for the 1988-89 operating year. In satisfaction of all obligations to MPC under Northwest Power Act section 9(1)(3), MPC's Exhibit B amount is set at 105 MW to facilitate long-term sales of firm power from its share of the Colstrip No. 4 coal-fired generating station. Exhibit B amounts for Tacoma and Cowlitz are increased to accommodate existing firm power transactions.

(B) **Shaping**. Firm power sales eligible for Assured Delivery may be shaped within the following ranges. During the months of September through December, a Scheduling Utility may deliver firm energy at a rate up to 1.8 times its Exhibit B average firm surplus amount. During the months of January through August, a Scheduling Utility may deliver firm energy at a rate no greater than 1.0 times its Exhibit B amount. However, total delivered energy may not exceed the Exhibit B annual firm energy maximum.

(C) **Other uses of Exhibit B amounts**. BPA will not entertain Assured Delivery requests for firm power sales in excess of a utility's Exhibit B maximum. However, a Scheduling Utility may use any portion of its Exhibit B maximum, not used for firm power sales, for exchange transactions supported by Qualified Northwest Resources.

(D) **Future changes**. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount will be revoked if, upon revision, a utility's individual Exhibit B amount has declined or if a utility has sold firm power to another utility seeking to increase its Exhibit B

average firm surplus amount. A Scheduling Utility may increase its individual Exhibit B amount by purchasing surplus firm power from BPA or any Scheduling Utility with an Exhibit B amount.

(3) **Other Capacity**. The remaining capacity available for Assured Delivery under this policy is offered to Scheduling Utilities, on a first-come, first-served basis, for Exchange transactions supported by Qualified Northwest Resources. When section 4(c)(2)(D) of this policy is implemented to reduce the Exhibit B maximum of any Scheduling Utility, the reduction will be added to the capacity made available under this provision. Any utility with an Exhibit B amount must exhaust such capacity before requesting Assured Delivery under this provision.

(d) **Mitigation**

(1)**Operational Mitigation**

(A) **Southbound deliveries**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures to preschedule energy deliveries, each utility's Assured Delivery amount shall be deducted from its formula allocation to determine its share of energy scheduled on the Intertie. If the remainder is negative for a given utility, then that utility must make up the difference by purchasing sufficient energy as follows:

(i) during Condition 1 from BPA or any Scheduling Utility with a Formula Allocation during that hour;

(ii) during Condition 2 from BPA, however, if BPA is not in the market the utility may purchase sufficient energy from any other utility.

(B) **Northbound returns**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures, a utility may utilize the cash-out provisions of an Exchange contract only by reducing one-for-one the amount of North-to-South Intertie capacity otherwise available to it under this policy. The rate of cash out during any condition shall not exceed the rate at which the exchange return could have been scheduled.

(2) **Negotiated mitigation**. A Scheduling Utility may also elect to negotiate with BPA on a case-by-case basis a package of mitigation measures involving mutually agreeable consideration of value commensurate with the service provided.

Section 5. **Formula Allocation Methods**

(a) **Limits On Intertie Capacity Available For Formula Allocation**. Generally, BPA will determine Intertie Capacity available for Formula Allocations after first taking into account the amount of Intertie Capacity necessary to satisfy requirements of the Administrator's Power Marketing Program, existing transmission contracts listed in Exhibit A, and Assured Delivery contracts executed by BPA pursuant to this policy. However, in determining Available Intertie Capacity during Condition 1, BPA will not consider the Assured Delivery contracts to the extent they are subject to operational mitigation requirements. BPA may reduce any allocation, if additional Intertie Capacity is required to minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.

(b) **Protected Area Decrements.** Except as provided in section 4(d)(2)(A) of this policy, BPA will reduce each Scheduling Utility's allocation by any Protected Area decrement imposed pursuant to section 7(d).

(c) **Allocation Methods.**

(1) **Condition 1**

(A) **Until December 31, 1988.** Intertie Capacity will be allocated pursuant to the Exportable Agreement (BPA Contract No. 14-03-73155), when applicable.

(B) **After December 31, 1988.** Condition 1 will be in effect when the Federal hydro system is in spill or there is a likelihood of spill, as determined by BPA. Available Intertie capacity will be allocated pursuant to the following procedure:

(i) Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective declarations to total declarations, multiplied by the Available Intertie Capacity.

(ii) During Condition 1, whenever BPA is unable to utilize its full pro rata share of intertie usage BPA will take larger allocations on ensuing days until the difference in pro rata intertie usage is eliminated.

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, Formula Allocations for BPA and each Scheduling Utility will approximate, by hour, the ratio of each declaration to the sum of all declarations, multiplied by the available Intertie capacity.

(B) If BPA sales drop below 75 percent of its allocation during Condition 2, BPA may take larger allocations on ensuing days until the difference is eliminated.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA and Scheduling Utilities' allocations will equal their declarations. The remaining Intertie capacity will be made available first to U.S. Extraregional Utilities and then to other Extraregional Utilities. Section 3(d) of this policy shall not apply to Scheduling Utilities during Condition 3.

(d) **Formula Allocation Experiment.** BPA is interested in exploring the proposal that it cease making individual Formula Allocations to Scheduling Utilities under Conditions 2 and 3. However, BPA must work with Northwest and Southwest utilities to develop the information capability to accommodate a new scheduling system for nonfederal access. As soon as this can be accomplished BPA will substitute the following provisions for section 5(c) on an 18-month experimental basis:

(1) **Condition 1**

Same as section 5(c)(1).

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, the Formula Allocation for BPA will approximate, by hour, the ratio of BPA's declaration to the sum of all declarations, multiplied by the Available Intertie Capacity. The remaining capacity will be made available as a block to Scheduling Utilities. Section 5(c)(2)(B) of this policy shall apply.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA's allocation will equal its declaration. The remaining Intertie capacity will be made available, first, as a block to satisfy the declarations of Scheduling Utilities, second, to U.S. Extraregional Utilities, and third to other Extraregional Utilities. Section 3(d) of this policy shall not apply during Condition 3.

(e) **Data Collection and Evaluation.** Commencing when this policy goes into effect and continuing during the course of the experiment described in section 5(d), BPA will collect information on the following topics relevant to future allocation procedures:

(1) effect on BPA revenue of allocating to nonfederal utilities as a group rather than individually.

(2) impairment of Intertie access for California utilities presently lacking ownership in the southern portion of the Intertie,

(3) any loss of sales to BPA due to a failure to share unused capacity among California entities with ownership or contractual interests in the Intertie,

(4) effects of the experiment on small Scheduling Utilities.

During the course of the experiment, interested parties may submit written comments and recommendations on these issues.

(f) **Findings and conclusions.** At least 30 days before the end of the experiment described in section 5(d), BPA shall publish a report of its findings on the experiment and its decision on whether section 5(d), with possible modification, should be continued as the permanent method of Formula Allocation.

Section 6. **Access for Qualified Extraregional Resources**

(a) **Assured Delivery.** Any request for Assured Delivery of power from a Qualified Extraregional Resource would be granted only by contract which, in addition to the Mitigation measures specified in section 4(d), must include

benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether they would cause substantial interference with the Administrator's Power Marketing Program. An environmental review would also be conducted.

(b) **Formula Allocation**. Under Condition 3, energy from Qualified Extraregional Resources has access to the Intertie. In addition, BPA may provide Extraregional Utilities with Formula Allocation under other conditions, if the utility agrees by contract either to increased participation in the Pacific Northwest's coordinated planning and operation, or to provide other consideration of value, apart from the standard BPA wheeling rate, commensurate with the services provided.

Section 7. **Fish and Wildlife Protection**

(a) **Purpose**. New hydroelectric projects constructed in Protected Areas may substantially decrease the effectiveness of, or substantially increase the need for, expenditures and other actions by BPA, under Northwest Power Act section 4(h), to protect, mitigate or enhance fish and wildlife resources. Intertie access will not be provided to facilitate the transmission of power generated by any new hydroelectric projects located in Protected Areas and licensed after the effective date of this policy. This provision does not apply to added capacity at existing projects.

(b) **Effect**. This section imposes automatic operational limitations on a utility by reducing the amount of energy that can be scheduled over the Intertie, thereby increasing costs or reducing revenues for any utility owning or acquiring the output of a Protected Area hydroelectric resource.

(c) **Implementation**. Protected Area designations for stream reaches in the Columbia River Basin are shown in Exhibit C to this policy. Exhibit C uses Environmental Protection Agency stream reach codes. Subject to review and possible modification, BPA will consider the adoption of comprehensive state watershed management plans and a comprehensive protected area program developed by the Pacific Northwest Electric Power and Conservation Planning Council subsequent to implementation of this policy. BPA will also consider revisions to Protected Area designations if the Council's Program is amended.

(d) **Enforcement**. If a Scheduling Utility or Nonscheduling Utility owns, or acquires the output from, a hydroelectric project covered under the restrictions of section 7(a), BPA will reduce that utility's Formula Allocation by either the nameplate rating of the project (in the case of ownership), or the amount of capacity acquired by contract.

(e) **Exceptions**.

(1) **PURPA Projects**. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an investor-owned utility has been compelled to acquire the output of a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act (PURPA). To qualify for this exception, the investor-owned utility must demonstrate:

(A) that it has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the Protected Area resource in question;

(B) that it has petitioned its state regulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources in recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy;

(C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and

(D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that it was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

(2) **Projects Contributing to Council's Fish and Wildlife Program or BPA Investments**. Access will be automatically denied for projects developed in protected areas unless BPA receives sufficient demonstration that a particular project will provide benefits to existing or planned BPA fish and wildlife investments or the Council's Program. BPA's determination will be based on:

(A) information provided by the project developer, Federal and state fish and wildlife agencies, and tribes; or

(B) action by the Pacific Northwest Power Planning Council.

Section 8. **Other Enforcement Provisions**

(a) Whenever the terms of this policy are not being met, BPA will inform the appropriate utility of the nature of the noncompliance and actions that may be taken to achieve compliance. If noncompliance is not corrected within a reasonable period, BPA may deny access for a resource and refuse to accept schedules.

(b) Upon approval of the proposed U.S.-Canada Free Trade Agreement by the Canadian Parliament and the United States Congress, any and all distinctions made in this policy between Canadian and United States Extraregional Utilities shall terminate on the effective date of the Agreement.

EXHIBIT A
EXISTING AGREEMENTS FOR INTERTIE CAPACITY

This is a list of existing BPA transmission contracts that were signed before the implementation of the NTIAP and will continue to receive Intertie access under the LTIAP.

Utility	BPA Contract No.	Expiration Date
Washington Water Power Company	DE-MS79-81BP90185	07/01/91
Washington Water Power Company	14-03-791101	09/01/88
Western Area Power Administration	DE-MS79-84BP91627	10/31/90

EXHIBIT B
INTERTIE CAPACITY AVAILABLE FOR ASSURED DELIVERY

BPA has reserved 800 MW of Intertie capacity to be available for nonfederal firm transactions. This capacity is allocated as follows:

A. **Average Firm Surplus Allocations:**

UTILITY	AVERAGE MW FIRM SURPLUS	
Chelan County PUD #1	10	
Cowlitz County PUD #1	45	1/
Douglas County PUD #1	0	2/
Eugene Water and Electric Board	14	
Grant County PUD #1	26	
Seattle City Light	23	
Snohomish County PUD #1	0	
Tacoma City Light	41	3/
Idaho Power Company	87	
Montana Power Company	105	4/
Puget Sound Power and Light	0	
Washington Water Power	93	
	444	

NOTE: The Average Firm Surplus (AFS) is directly from the PNUCC Northwest Regional Forecast of March 1987 for the period 1988-89 except as noted below. It includes resources operational on the effective date of this policy. Export contracts are included as loads. Utilities may use their AFS allocations for long term firm sales or for exchanges. Portland General Electric Company and Pacific Power & Light Company are not eligible for an AFS allocation because of their existing interconnections with the Southwest.

1/ Cowlitz Co. PUD's AFS is the amount of their existing export of the Longview Fibre resource. Longview Fibre is considered to be a Federal resource in the Northwest Regional Forecast and is not included under Cowlitz.

2/ Douglas County PUD's AFS is 2; but Douglas has previously requested to show zero.

3/ The amount displayed for Tacoma is the amount of their existing exports displayed in the Northwest Regional Forecast.

4/ Montana Power Company's AFS was increased from 80 MW to 105 MW in settlement of obligations under Northwest Power Act section 9(1)(3).

B. **Intertie Capacity Available for Exchanges:** The above allocations for sales of firm surplus may be used for exchanges. The remaining 356 MW of capacity is available on a first come-first serve basis for exchanges only under the terms of the LTIAP. If there is a decrease in a utility's firm surplus and the utility does not have a contract for that amount, BPA will allocate the difference to capacity available for exchanges by revising this Exhibit B.

EXHIBIT C
PROTECTED AREAS

Exhibit C corresponds to the Northwest Power Planning Council protected area designations within the Columbia Basin, as specified in the Columbia River Basin Fish and Wildlife Program. Stream reaches designated as protected areas are identified by Environmental Protection Agency stream reach codes. Information about designations are contained on hard copy computer printouts or computer diskette copies which are available to the public upon request.

This revision reduces the Transmission Demand from 125 MW to 93 MW on lines C.1.b. and C.2.b. due to implementation of the Capacity Ownership Agreement, Contract No. DE-MS79-95BP94628.

TRANSMISSION PARAMETERS

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1/]

1. North-to-South Transactions:

a.	01/01/94 to 05/31/94:	75 MW
b.	06/01/94 to 12/31/94:	125 MW
c.	01/01/95 and thereafter:	93 MW

2. South-to-North Transactions:

a.	01/01/94 to 05/31/94:	75 MW x Intertie South-to-North RTC ÷ 4800 MW
b.	06/01/94 to 12/31/94:	125 MW x Intertie South-to-North RTC ÷ 4800 MW
c.	01/01/95 and thereafter:	93 MW x Intertie South-to-North RTC ÷ 4800 MW

1/ Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Account Executive

Name Patrick G. McRae
(Print/Type)

Date January 11, 1995

PACIFICORP

By _____

Name Jerry D. Miller
(Print/Type)

Title Manager, Power System Services

Date January 23, 1995

(PMLAN-MPSM-W:\PMT\CT\94285c_1.DOC)

AUTHENTICATED

Service Agreement No. 00TX-10367

SERVICE AGREEMENT
for
POINT-TO-POINT
TRANSMISSION SERVICE
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP POWER MARKETING, INC.

1. This Service Agreement, dated as of 11/1/2000, is entered into, by and between the Bonneville Power Administration Transmission Business Line (the "Transmission Provider") and PacifiCorp Power Marketing, Inc. (the "Transmission Customer").

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point ("PTP") Transmission Service under the Tariff.

3. The Transmission Customer has provided to the Transmission Provider an Application deposit, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.

4. Service under this Service Agreement shall commence on 2400 hours on September 30, 2001, and shall terminate on 2400 hours on September 30, 2010.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit B.

7. The Tariff is incorporated herein and made a part hereof.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. Should the Commission, in an order issued pursuant to the Transmission Provider's filing of the Tariff and this Service Agreement for reciprocity purposes, disapprove any provision of this Service Agreement, the parties shall amend the Service Agreement to comply with the Commission's order. The Transmission Provider shall prepare an amendment for execution as soon as reasonably practicable after issuance of the Commission's order.

11. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(I) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Tariff.

IN WITNESS WHEROF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PACIFICORP POWER MARKETING	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C. VAN ALDERWALT	By: /S/ MICHAEL RASCHIO
Name: Peter C. van Alderwerelt *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: Managing Director	Title: Transmission Account Executive
Date: 11-1-00	Date: 10/24/00

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EXHIBIT A
SPECIFICATIONS FOR LONG-TERM
FIRM POINT-TO-POINT TRANSMISSION SERVICE

Not applicable at this time.

EXHIBIT B
NOTICES

1. NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, First Class mail, by telefax or sent by acknowledged delivery.

If to the Transmission Customer:

Contract Administration
PacifiCorp Power Marketing,Inc.
830 NE Holladay, Suite 200
Portland, Oregon 97232
Attention: Jan Wolsleben
Title: Contract Administrator
Phone: (503) 813-5703
Fax: (503) 813-5707

If to the Transmission Provider:

Bonneville Power Administration
P. O. Box 491
Vancouver, WA 98666-0491
Attention: Transmission Account Executive for PacifiCorp Power Marketing - TM-Ditt2
Phone: (360) 418-8695
Fax: (360) 418-8320

2. NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by telefax or sent by First Class mail or acknowledged delivery.

If to the Transmission Customer:

PacifiCorp Power Marketing,Inc.
830 NE Holladay, Suite 200
Portland, Oregon 97232
Attention: Rob Goodman
Title: Mngr, Transaction Trading
Phone: (503) 813-7158
Fax: (503) 813-5700
Attention: Real Time Desk
Phone: (503) 813-5752
Fax: (503) 813-5700

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
TOD-DITT1
Vancouver, WA 98666-0491
Attention: Outage Dispatcher (Dittmer)
Phone: (360) 418-2274 *(outage planning)*
Phone: (360) 418-2281 *(real time)*
Fax: (360) 418-2938
Attention: System Dispatcher (Dittmer)
Phone: (360) 418-2281 *(real time)*
Fax: (360) 418-2938
Attention: Munro Control Center
Phone: (509) 465-1820 *(real time)*
Phone: (509) 466-2409 *(outage planning)*
Fax: (509) 466-2444

3. **SCHEDULING AGENT**

The Transmission Customer has designated the following scheduling agent.

Scheduling Agent
PacifiCorp Power Marketing, Inc.
830 NE Holladay, Suite 250
Portland, Oregon 97232
Attention: Scheduling
Phone: (503) 813-6078
Fax: (503) 813-5700
Attention: Real Time Desk
Phone: (503) 813-5752
Fax: (503) 813-5700

AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

REVISION NO. 3, TABLE 1
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 386501

This Revision No. 3 to Table 1 adds the Klamath Expansion Project as a resource to be integrated at the City of Klamath Falls Cogeneration Project Substation effective December 1, 2002.

1. TERM OF TRANSACTION

Commencement Date: at 0000 hours on October 1, 2001.[1]
Termination Date: at 0000 hours on May 1, 2007.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
City of Klamath Falls Cogeneration Project	City of Klamath Falls Cogeneration Project Substation 500 kV	BPA	95,000[2]	COB 500 kV	BPA	95,000[2]	BPA
Klamath Expansion Project							
Total Reserved Capacity			**95,000[2]**			95,000[2]	

3. POINT(S) OF RECEIPT

City of Klamath Falls Cogeneration Project Substation

Location: tap into Pacificorp's Meridian-Captain Jack on the 500 kV Transmission Line at City of Klamath Falls Co-generation Project Substation;

Voltage: 500 kV.

---

[1] This Revision No. 2 to Table 1 of Exhibit A covers the remaining period of this 6-year transaction; the first 5 months are covered under Exhibit C, Revision 1 to Contract No. 99TX-20112, which expires at 0000 hours on October 1, 2001.

[2] Firm Reserved Capacity associated with this reservation shall be contingent upon operation of the Project; transmission will be on a one-for-one basis with the Project's generation level when less than 95 MW.

4. **POINT(S) OF DELIVERY**

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where Bonneville shall make electric power available for the ISO hereunder;

Voltage: 500 kV.

5. **SERVICE AGREEMENT CHARGES**

Service under this Agreement will, in addition to those charges detailed in Exhibit A, be subject to the charges detailed below. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

Transmission Charge: PTP-02 Rate Schedule or successor rate schedules.

6. **REAL POWER LOSS FACTORS**

Real Power Loss Factors are identified in BPA's Open Access Transmission Tariff under Schedule 9.

Exception: A loss factor of 1.5 percent shall be applied to all schedules from the Klamath Falls Point of Receipt to the COB Point of Delivery. The general Loss Factors identified in Schedule 9 of the Tariff shall apply to all other schedules under this Agreement. In no event shall BPA revise the Transmission Customer's IS Loss Factor, as set forth above, to an amount above 1.5 percent prior to October 1, 2003. BPA shall prepare a new Exhibit A incorporating any Revision and the revised Exhibit shall become effective as of the date specified therein.

PACIFICORP POWER MARKETING	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VAN ALDERWERELT	By: /S/ MICHAEL A RASCHIO
Name: Peter C Van Alderwerelt *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: Vice President	Title: Transmission Account Executive
Date: 1/6/03	Date: 12/10/02

AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 5
REQUEST FOR TRANSMISSION SERVICES
The OASIS Assignment Reference Number (ARef) is: 386513

1. TERM OF TRANSACTION

Commencement Date: at 0000 hours on July 1, 2005.
Termination Date: at 0000 hours on July 1, 2006.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
City of Klamath Falls Cogeneration Project	City of Klamath Falls Cogeneration Project Substation 500 kV	BPA	100,000	California Oregon Border 500 kV	California ISO	100,000	California ISO or other parties with rights to receive power at COB
Klamath Expansion Project							
Total Reserved Capacity			100,000			100,000	

3. POINT(S) OF RECEIPT

City of Klamath Falls Cogeneration Project Substation

Location: tap into PacifiCorp's Meridian-Captain Jack on the 500 kV Transmission Line at City of Klamath Falls Co-generation Project Substation;

Voltage: 500 kV.

4. POINT(S) OF DELIVERY

California Oregon Border

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make Electric power available for the Transmission Customer hereunder;

Voltage: 500 kV.

5. SERVICE AGREEMENT CHARGES

Service under this Agreement will, in addition to those charges detailed in Exhibit A, be subject to the charges detailed below. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

Transmission Charge: IS-04 Rate Schedule

Reservation Fee

Within 30 days after the Transmission Customer signs this Table 5 of Exhibit A, the first annual nonrefundable reservation fee of $117,600 shall be paid to the Transmission Provider. For the second and any subsequent reservation fees, the Transmission Provider will bill the Transmission Customer 30 days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS Rates only and does not include either of the two Ancillary Services that the Transmission Customer is obligated to purchase from the Transmission Provider.

6. REAL POWER LOSS FACTORS

Real Power Loss Factors are identified in BPA's Open Access Transmission Tariff under Schedule 9.

Exception: A loss factor of 1.5 percent shall be applied to all schedules from the Klamath Falls Point of Receipt to the COB Point of Delivery. The general Loss Factors identified in Schedule 9 of the Tariff shall apply to all other schedules under this Agreement. BPA has the unilateral right to modify the 1.5 percent loss factor with a 60-day notice to the Transmission Customer. BPA shall prepare a new Exhibit A incorporating any Revision and the revised Exhibit shall become effective as of the date specified therein.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VAN ALDERWELT	By: /S/ MICHAEL A RASCHIO
Name: Peter C. van Alderwerelt *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: Vice President	Title: Transmission Account Executive
Date: 10/27/03	Date: 10/16/03

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AUTHENTICATED

EXHIBIT A, TABLE 9
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. 9 adds 42 MW of Intertie transmission demand at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD).

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2006
Termination Date: at 0000 hours on January 1, 2007

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 960250							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	42,000[3]	COB (500 kV)	BPA	42,000	CISO (PPM)

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

---

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $52,836 shall be paid to the Transmission Provider. For the second reservation fee, the Transmission Provider will bill the Transmission Customer thirty days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS rate only and does not include Ancillary Services.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C. VAN ALDERWERELT	By: /S/ BRIAN D ALTMAN
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Brian D. Altman *(Print/Type)*
Title: **Senior Vice President**	Title: Transmission Account Executive
Date: **8/3/04**	Date: **16 July 2004**

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AUTHENTICATED EXHIBIT A, TABLE ~~17~~8

SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. ~~17~~8 (Oasis No. 753) adds 75 MW of intertie transmission demand at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD).

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2006
Termination Date: at 0000 hours on January 1, 2007

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 960248							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	75,000[3]	COB (500 kV)	BPA	75,000	CISO (PPM)

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal

4. POINT(S) OF DELIVERY

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable.

6. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

Not applicable.

7. SERVICE AGREEMENT CHARGES

(a) **Transmission Charge**
PTP-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $88,200 shall be paid to the Transmission Provider. For the second and subsequent reservation fees, the Transmission Provider will bill the Transmission Customer thirty days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the PTP Rate in effect at the time each payment is due. The Reservation Fee is based on the PTP rate only and does not include Ancillary Services.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ PETER VAN ALDERWERELT**	By: **/S/ MICHAEL A RASCHIO**
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **6/8/04**	Date: **5/24/04**

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EXHIBIT A, TABLE 10
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. 10 adds 8 MW of Intertie transmission at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD).

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2006
Termination Date: at 0000 hours on January 1, 2007

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 1313745							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	8,000[3]	COB (500 kV)	BPA	8,000	CISO (PPM)

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

---

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal.

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $8,224 shall be paid to the Transmission Provider. For the second reservation fee, the Transmission Provider will bill the Transmission Customer thirty days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS rate only and does not include Ancillary Services.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/s/ Peter C. van Alderwerelt**	By: **/s/ Thomas M. Noguchi** **for**
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
JE T.N.	
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **10/26/04**	Date: **10/13/04**

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EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 11
ASSIGNMENT OF TRANSMISSION SERVICE

This Revision No. 11 reflects an assignment [1] of transmission service under this Service Agreement from the Assignor, Hermiston Power Partnership (HPP), to Assignee, PPM Energy, Inc. (PPM), and is contingent upon execution of such assignment. This Revision adds 50 MW of intertie transmission demand at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD). This assignment replaces the assignment executed on February 27, 2004 under Revision No. 7. These changes become effective on the Start Date, January 1, 2005.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2005.
Termination Date: at 0000 hours on January 1, 2006

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 1364703							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[2]	John Day Substation 500 kV	BPA[3]	50,000[4]	COB (500 kV)	BPA	50,000[4]	CISO (PPM)
Total Reserved Capacity			50,000			50,000	

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

---

[1] See HPP Contract No. 98TX-10154, Revision 11 to Exhibit A
[2] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[3] Bonneville Power Administration (BPA).
[4] This transmission demand is not entitled to Right of First Refusal

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
PTP-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VANALDERWERELT	By: /S/ NANCY E MORGAN
Name: **Peter C vanAlderwerelt** *(Print/Type)*	Name: **Nancy E. Morgan** *(Print/Type)*
Title: **Sr. Vice President**	Title: **Transmission Sales Manager**
Date: **11/30/04**	Date: **1/7/05**

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EXHIBIT A
TABLE 12
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. 12 provides for 180 MW of Transmission Service from the John Day Point of Receipt to the California Oregon Border Point of delivery. Service to begin January 1, 2005, and end January 1, 2009. This Table 12 becomes effective on the date of execution.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2005.
Termination Date: at 0000 hours on January 1, 2009

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 1362012							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	180,000[3]	COB (500 kV)	BPA	180,000	CISO (PPM)
Total Reserved Capacity			180,000			180,000	

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal.

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
PTP-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VAN ALDERWERELT	By: /S/ NANCY E MORGAN
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Nancy E. Morgan *(Print/Type)*
Title: **Sr. Vice President**	Title: Acting Transmission Sales Manager
Date: **12/13/04**	Date: **11-24-04**

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MOA No. 96MS-95363
Final Draft Dated 3/21/97

AUTHENTICATED

MEMORANDUM OF AGREEMENT
providing for
POINT-TO-POINT TRANSMISSION SERVICE
between the
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE
and the
BONNEVILLE POWER ADMINISTRATION
POWER BUSINESS LINE

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Exhibit A	(Point-to-Point Transmission Service Terms and Conditions (Tariff))
Exhibit B	(Application for Point-to-Point Transmission Service)
Exhibit C	(Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit D	(System Impact Study Agreement)
Exhibit E	(Facilities Study Agreement)
Exhibit F	(Transmission Scheduling Provisions)
Exhibit G	(Reservation Confirmation Request for Short-Term Point-to-Point)
Exhibit H	(Wholesale Power and Transmission Rate Schedules)
Exhibit I	(Facilities Charges)

This MEMORANDUM OF AGREEMENT (MOA) is signed this 25th day of March, 1997, by and between the Bonneville Power Administration Transmission Business Line (hereinafter referred to as "Transmission Business Line") and the Bonneville Power Administration Power Business Line (hereinafter referred to as "Power Business Line"). The Bonneville Power Administration, as a whole, will be referred to as "BPA." The Transmission Business Line and the Power Business Line are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below. It is the intent of the Parties to implement the administrative separation and transmission comparability principles of the Federal Energy Regulatory Commission (Commission) through this MOA.

ARTICLE 1
SCOPE

1.1 **Terms and Conditions.** The terms and conditions under which the Point-to-Point (PTP) Transmission Service is provided are pursuant to this MOA and to the PTP Transmission Service Terms and Conditions (Tariff). The Tariff in effect at the time of signature of this MOA is hereby incorporated by this reference and made a part of this MOA as Exhibit A. The Transmission Business Line is "Bonneville" as that term is used in the Tariff. Because the Transmission Business Line and the Power Business Line are legally the same entity, the following provisions of the Tariff do not apply; provided, however, that such provisions of the Tariff shall apply to the extent rights hereunder are assigned pursuant to section 15.0 of the Tariff:

1.1.1 section 7.5 [parallel path provisions];

1.1.2 section 7.3 [reciprocity];

1.1.3 section 18.2 [stranded costs];

1.1.4 section 20.1(b), 20.1(c), 20.1 (f) and 20.1(g) [billing and payment];

1.1.5 sections 6.4 and 24 [dispute resolution];

1.1.6 section 21 [regulatory filings];

1.1.7 section 22 [liability and indemnification]; and

1.1.8 section 23 [creditworthiness].

Unless otherwise mutually agreed in writing by the Parties, the Transmission Business Line may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory or preferential. The Parties agree that transmission service provided pursuant to this MOA may be provided under a Commission-approved successor tariff after September 30, 2001, if the Transmission Business Line implements a tariff that supersedes the Tariff.

1.2 **Application.** The Application for Firm Point-to-Point (PTP) Transmission Service requested by the Power Business Line and accepted by the Transmission Business Line for this MOA is hereby incorporated by this reference and made a part of this MOA as Exhibit B.

1.3 **Statement of Specifications for Long-Term Firm Transmission Service.** The Statement of Specifications (including Ancillary Services) for Long-Term Firm Point-to-Point Transmission Service under this MOA requested by the Power Business Line and accepted by the Transmission Business Line are hereby incorporated by this reference and made a part of this MOA as Exhibit C.

1.4 **System Impact/Facilities Study.** Study Agreements for a System Impact Study and/or a Facilities Study, if performed pursuant to this MOA, are hereby incorporated by this reference and made a part of this MOA as Exhibits D and E, respectively.

1.5 **Transmission Scheduling Provisions.** The Transmission Scheduling Provisions are hereby incorporated by this reference and made a part of this MOA as Exhibit F. All transactions under this MOA shall be scheduled in accordance with the Transmission Scheduling Provisions in Section 2.7(d) of the Tariff and Exhibit F of this MOA.

1.6 **Reservation Confirmation Request for Short Term PTP.** The Reservation Confirmation Request for Short Term PTP is hereby incorporated by this reference and made part of this MOA as Exhibit G. The service specifications for Short-Term Firm and Nonfirm transmission service under this MOA shall be as provided in Exhibit G.

1.7 **BPA Wholesale Power and Transmission Rate Schedules.** The BPA Wholesale Power and Transmission Rate Schedules are hereby incorporated by this reference and made part of this MOA as Exhibit H.

1.8 **Facilities Charges.** All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this MOA are hereby incorporated by this reference and made a part of this MOA as Exhibit I.

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the Tariff.

ARTICLE 3
TERM

Service under this MOA shall commence on 2400 hours on September 30, 1996, and terminate on 2400 hours on March 31, 2017. This MOA may be terminated prior to March 31, 2017 as provided in the Tariff. Specific terms of service for individual long-term firm transactions under this MOA are provided in Exhibit C.

ARTICLE 4
CHARGES AND PAYMENTS

The Power Business Line shall transfer to the Transmission Business Line sufficient funds to cover the following charges as applicable, pursuant to Commission pricing policy, for transmission service provided hereunder.

4.1 Charges for Transmission Service. The Power Business Line shall pay the Transmission Business Line for charges as applicable for services provided hereunder pursuant to the rate schedules in Exhibit H.

4.1.1 All applicable charges pursuant to the Point-to-Point Transmission Rate (PTP-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules), as specified in Exhibit C and Exhibit G;

4.1.2 All applicable charges pursuant to the Ancillary Products and Services Rate (APS-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit C and Exhibit G;

4.1.3 Reserved Nonfirm Transmission Rate (RNF-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit G;

4.1.4 Energy Transmission Rate (ET-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit G;

4.1.5 Advance Funding Rate (AF-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) for facilities listed in Exhibit I;

4.1.6 Use-of-Facilities Rate (UFT-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) for facilities listed in Exhibit I;

4.1.7 Southern Intertie Rate (IS-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit C and Exhibit G;

4.1.8 Montana Intertie Rate (IM-96, or its successor, as revised as listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit G.

4.2 Billing and Payment. Bills for all services provided under this MOA shall be rendered monthly by the Transmission Business Line and all such bills shall be due and payable in accordance with section 20 of the Tariff and Article 1.1.4 of this MOA, as appropriate, or as otherwise agreed by the Parties.

ARTICLE 5
NOTICES

5.1 Notices Relating to Provisions of this MOA. Any notice, request, demand, or statement which may be given to or be made upon either Party by the other Party under any of the provisions of this MOA, except those specified in paragraph 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If the notice is to the Power Business Line:

Bonneville Power Administration, Power Business Line
Contact: Manager, Transmission Services - PST
905 NE 11th Avenue
P.O. Box 3621
Portland, OR 97208-3621

If the notice is to the Transmission Business Line:

Bonneville Power Administration, Transmission Business Line
Contact: Account Executive for the Power Business Line - TM
905 NE 11th Avenue
P.O. Box 3621
Portland, OR 97208-3621

5.2 **Notices of an Operating Nature.** Any notice, request, or demand pertaining to matters of an operating nature, including notices required pursuant to Article 8.4 but exclusive of requests for additional or modified transmission service under this MOA, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should the same not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. Point(s) of contact pursuant to this section shall be communicated by the Parties under separate letter within 45 days from the date this MOA is signed.

ARTICLE 6
SYSTEM OPERATIONS

The Power Business Line, having Points of Interconnection with Federal Columbia River Transmission System (FCRTS), shall be required to designate a Control Area and to comply with the System Operation and Interconnection Requirements in section 7.4 of the Tariff prior to commencement of PTP Transmission Service hereunder. Points of Delivery in Exhibits C and G shall be governed by agreements between the Transmission Business Line and parties interconnected with the FCRTS.

ARTICLE 7
SPECIFICATIONS FOR ANCILLARY SERVICES

Ancillary Services provided by the Transmission Business Line to the Power Business Line pursuant to this MOA shall be provided in accordance with section 8 of the Tariff, and shall

be billed in accordance with section 20 of the Tariff and Articles 1.1.4 and 4.2 of this MOA. The Ancillary Services provided to the Power Business Line shall be specified in the Statement of Specifications, Exhibit C and in Exhibit G of this MOA. The Power Business Line shall pay the Transmission Business Line for such Ancillary Services.

ARTICLE 8
MISCELLANEOUS

8.1 **Interconnection with Other Systems.** Nothing contained in this MOA shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this MOA or amending or entering into such agreements.

8.2 **Governing Law.** This MOA shall be interpreted, construed, and enforced in accordance with Federal law.

8.3 **Amendments.** Except as provided in Article 1.1 and Article 8.4, and unless otherwise mutually agreed in writing by the Parties, the Transmission Business Line may change this MOA upon, and only upon, a determination by the Commission that such change is just, reasonable and not unduly discriminatory or preferential. Otherwise, this MOA may be amended upon mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

8.4 **Revision of Exhibits.** If the Transmission Business Line determines that any changes to Exhibits C, D, E, F, G, H, or I are necessary to reflect changes specified below, such new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein.

8.4.1 If the Parties mutually agree to change Exhibit C pursuant to this MOA, the Transmission Business Line shall prepare and issue a revised Exhibit C, or Table thereto, as appropriate. The Transmission Business Line reserves the

right to amend contiguous Point of Delivery provisions in section 3 of the Index and General Specifications of Exhibit C.

8.4.2 If the Parties mutually agree to perform a System Impact Study and/or Facilities Study, the Transmission Business Line shall prepare a revised Exhibit D and/or Exhibit E, as applicable, incorporating the System Impact Study and/or Facilities Study, the associated Study Agreement(s), and any supporting or clarifying documents as agreed.

8.4.3 For changes to any of the provisions contained in the Transmission Scheduling Provisions Exhibit (Exhibit F) to reflect updated transmission scheduling practices, the Transmission Business Line shall prepare a new Exhibit F to be incorporated into this MOA.

8.4.4 For changes to the Reservation Confirmation for Short-Term PTP (Exhibit G) to reflect updated reservation confirmation practices, the Transmission Business Line shall prepare a new Exhibit G to be incorporated into this MOA.

8.4.5 The Transmission Business Line may change rates pursuant to applicable law and procedures. The Transmission Business Line shall prepare a new Exhibit H reflecting such changes, and such new Exhibit H shall be incorporated into this MOA.

8.4.6 The Transmission Business Line reserves the right to revise Exhibit I annually to reflect changes in: (a) the yearly noncoincidental demands on the facility under this MOA and other agreements; (b) changes in Investment and Amortization (I&A) annual cost ratio; and (c) changes in Operation and Maintenance (O&M) annual cost. The Transmission Business Line shall prepare a new Exhibit I reflecting such changes, and such new Exhibit I shall be incorporated into this MOA.

8.5 **Conversion to Future Tariffs.** Upon mutual agreement of the Parties, the notice periods for terminating this MOA and for commencing service under another tariff offered by the Transmission Business Line may be shortened.

8.6 **Temporary Load Shifts and Maintenance Notification.** The Parties may temporarily interrupt or reduce deliveries of electric power if either party determines that such interruption or reduction is necessary or desirable in case of system emergencies, operational constraints, Uncontrollable Forces, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on facilities used to make deliveries under this MOA. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of such interruption or outage.

Load shift and outage reports must be submitted to the Transmission Business Line within four (4) days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. The point of contact will be designated pursuant to Article 5.2 of this MOA. On receipt of the Power Business Line's data, the Transmission Business Line will take the appropriate steps to normalize the billing determinants at the affected point(s) of delivery. If Power Business Line reports are not received in a timely manner, the Transmission Business Line shall assess charges based on available data.

8.7 **Severability.** In the event any terms, covenants, or conditions of this MOA, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this MOA or any amendment hereto, and their application shall remain in full force and effect.

8.8 **Computation of Time.** On computing any period of time prescribed or allowed by this MOA, the day of the act, event, or default from which the designated period of

time begins to run shall not be included. The last day of this period so computed shall be included unless it is a Saturday, Sunday, or Federal holiday, in which event the period shall run until the end of the next business day which is neither a Saturday, Sunday, or Federal holiday. For purposes of the administration of this MOA, Pacific Time shall be used.

8.9 **No Third Party Beneficiaries.** This MOA creates rights and obligations only between the Parties hereto. The Parties hereto expressly do not intend to create any obligation or promise of performance to any other third person or entity nor have the Parties conferred any right or remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns to enforce this MOA.

8.10 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this MOA, or with respect to any other matter arising in connection with this MOA, shall not be deemed a waiver with respect to any other or subsequent default or matter.

8.11 **Successors and Assigns.** This MOA shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

8.12 **MOA Governs.** In the event of any irreconcilable difference between the Tariff and this MOA, the language of this MOA shall govern.

8.13 **Dispute Resolution.** All disputes between the Parties pursuant to this MOA shall be resolved by BPA's Chief Operating Officer.

8.14 **Entire Agreement.** This MOA constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect thereof.

IN WITNESS WHEREOF, the duly authorized representatives of the Transmission Business Line and the Power Business Line have signed this MOA as of the date first above written.

Bonneville Power Administration
Transmission Business Line

By /S/ ALLAN F. PASCHKE

Name Allan F. Paschke

Title Transmission Account Executive

Date 3/25/97

Bonneville Power Administration
Power Business Line

By /S/ TRACEY L. SALAZAR

Name Tracey L. Salazar
(Print/Type)

Title Manager Transmission Services
(Print/Type)

Date 3/25/97

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery at the California-Oregon Border (COB)

1. TERM OF TRANSACTION

Start Date: 2400 hours, March 31, 1997.
Termination Date: 2400 hours, March 31, 2017.

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various receiving parties.

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Pacific Gas & Electric

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation, 500 kV	COB, 500 kV	4/1/97-4/30/97: 571 MW	IS-96
		5/1/97-5/31/97: 431 MW	IS-96
		6/1/97-6/30/97: 531 MW	IS-96
		7/1/97-7/31/97: 631 MW	IS-96
		8/1/97-8/31/97: 631 MW	IS-96
		9/1/97-3/31/17: 700 MW	IS-96

6. DESCRIPTION OF POINTS OF INTERCONNECTION

JOHN DAY SUBSTATION

Location: the point in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

7. DESCRIPTION OF POINTS OF DELIVERY

CALIFORNIA/OREGON (COB) POINT OF DELIVERY

Location: the points in the Malin and Captain Jack Substations where the 500 kV facilities of PacifiCorp and the Government are connected;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

8. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable per section 1.1.2 of this MOA.

9. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

10. SHORT DISTANCE DISCOUNT

Not Applicable.

11. ANCILLARY SERVICES

a. Load Regulation

Load Regulation is provided by Pacific Gas & Electric.

b. Energy Imbalance

Deliveries are made to another control area.

Energy Imbalance is not required for this transaction.

c. Control Area Reserves for Resources

Control Area Reserves for Resources are provided pursuant to section 6(a) of the Index and General Specifications of this Exhibit C.

Control Area Reserves for Resources are not required for this transaction.

d. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are not required for this transaction.

e. Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Customer:
Modesto, Santa Clara, Redding (MSR)

1. TERM OF TRANSACTION

Start Date: 2400 hours, December 31, 1997
Termination Date: 2400 hours, April 15, 2013

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various Receiving Parties

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Pacific Gas & Electric

5. SUMMARY OF POINTS OF INTERTIE INTERCONNECTIONS AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day	COB, (500 kV)	01/01/98 - 04/15/2013: 150 MW	IS-96

6. DESCRIPTION OF POINTS OF INTERCONNECTION

John Day Substation

Location: the point in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: Quantities are to be scheduled.

7. DESCRIPTION OF INTERTIE POINTS OF DELIVERY

California/Oregon (Cob) Point Of Delivery

Location: the points in the Malin and Captain Jack Substations, where the 500 kV facilities of PacifiCorp and the Government are connected;

Voltage: 500 kV;

Metering: Quantities are to be scheduled.

8. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable per section 1.1.2 of this MOA

9. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None

10. SHORT DISTANCE DISCOUNT

Not applicable

11. ANCILLARY SERVICES

a. Load Regulation
Load Regulation is provided by Pacific Gas & Electric.

b. Energy Imbalance
Deliveries are made to another control area. Energy Imbalance is not required for this transaction.

c. Control Area Reserves for Resources
Control Area Reserves for Resources are provided pursuant to section 6(a) of the Index and General Specifications of this Exhibit C. Control Area Reserves for Resources are not required for this transaction.

d. Control Area Reserves for Interruptible Purchases
Control Area Reserves for Interruptible Purchases are not required for this transaction.

e. Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

BONNEVILLE POWER ADMINISTRATION
Transmission Business Line

By: _____

Name: Allan F. Paschke

Title: Transmission Account Executive

Date: 12/11/97

ACCEPTED:
BONNEVILLE POWER ADMINISTRATION
Power Business Line

By: _____

Name: Tracey L. Salazar

Title: Manager, Transmission Services

Date: 12-12-97

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AUTHENTICATED

MOA No. 96MS-95363
Power Business Line Customer
Bay Area Rapid Transit
Effective at 0000 hours
on August 1, 2002

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Customer: Bay Area Rapid Transit (BART)

This Table 60 reflects a conversion of the Intertie segment of long-term firm transmission service associated with Power Sales Contract No. 96MS-95177 from the Statement of Principles, Memorandum of Agreement No. 96MS-96060, to this PTP Agreement.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on August 1, 2002.
Termination Date: at 0000 hours on July 1, 2016.

2. SUMMARY OF POINT OF INTERCONNECTION AND POINT OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY

2.1 Oasis Assignment Reference Number: 483765

Effective Dates	Delivering Party (Resource)	POI	POI Control Area	Maximum POI Demand (MW)[1]	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
8/1/2002 - 6/30/2003	PBL Contract with BART (Contract No. 96MS-95177)	John Day Substation, 500 kV	TBL	14 MW	California-Oregon Border	PG&E	14 MW	Various Receiving Parties
7/1/2003 - 6/30/2016	PBL Contract with BART (Contract No. 96MS-95177)	John Day Substation, 500 kV	TBL	50 MW	California-Oregon Border	PG&E	50 MW	Various Receiving Parties

Maximum Reserved Capacity 50 MW

3. DESCRIPTION OF POINT OF INTERCONNECTION

John Day Substation

Location: the point in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

1 Conversion does not include Right of First Refusal (ROFR/Rollover).

4. DESCRIPTION OF POINT OF DELIVERY

California-Oregon Border (COB)

Location: the points in the Malin and Captain Jack Substations where the 500 kV facilities of PacifiCorp and the Government are connected;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED:
50 MW.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION:
Not applicable per section 1.12 of this MOA.

7. NAME (S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE:
Not applicable.

8. SERVICE UNDER THIS AGREEMENT WILL BE SUBJECT TO SOME COMBINATION OF THE CHARGES DETAILED BELOW. (THE APPROPRIATE CHARGES FOR TRANSACTIONS WILL BE DETERMINED IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE TARIFF).

8.1 Transmission Charge:
IS-02 Rate Schedule or Successor Rate Schedule.

8.1.1 Reservation Fee:
Not applicable.

8.1.2 Short Distance Discount:
Not applicable.

8.2 System Impact and/or Facilities Study Charge(s):
Facilities Charges are not required at this time for the service under this Table 60.

8.3 Direct Assignment and Use-of-Facilities Charges:
Facilities Charges are not required at this time for the service under this Table 60.

8.4 Ancillary Service Charges:
ACS-02 Rate Schedule or Successor Rate Schedule.

8.4.1 Ancillary Services are provided as follows:

		Provided By	Contract No.
8.4.1.1	**Scheduling, System Control And Dispatch**	Transmission Provider	96MS-95363
8.4.1.2	**Reactive Supply And Voltage Control**	Transmission Provider	96MS-95363
8.4.1.3	**Regulation & Frequency Response**	Transmission Provider	96MS-95363
		As Applicable	
8.4.1.4	**Energy Imbalance Service**	Transmission Provider	96MS-95363
		As Applicable	
8.4.1.5	**Operating Reserve – Spinning Reserve**	Transmission Provider	96MS-95363
		As Applicable	
8.4.1.6	**Operating Reserve – Supplemental Reserve**	Transmission Provider	96MS-95363
		As Applicable	

8.4.2 Notification of changes in Ancillary Services Provider:
Except for those Ancillary Services that must be provided by the Transmission Provider, the Transmission Customer may make an annual election to obtain some or all Ancillary Services from a third party or to self-supply Ancillary Services.

If the Transmission Customer intends that an entity other than the Transmission Provider provide any Ancillary Service for any Fiscal year (October 1 through September 30), then the Transmission Customer must notify the Transmission Provider of its election of an Ancillary Service provider by July 1 of each Fiscal Year. Such election will be effective October 1 of the next Fiscal Year. If the Transmission Customer does make such election, the Transmission Provider will notify the Transmission Customer no later than September 1 of the Fiscal Year prior to the Fiscal Year for which such election is made, whether the Transmission Customer's alternative arrangements are comparable to purchasing the Ancillary Services(s) from the Transmission Provider, and are consistent with the Transmission Provider's business practices for self-supply or third party supply.

In the event that, as to any Ancillary Service, the Transmission Customer's alternative arrangements are *not* comparable, or are inconsistent with the Transmission Provider's business practices for self-supply or third party supply, the Ancillary Service provider for such Ancillary Service for the next Fiscal Year shall be the Transmission Provider.

9. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom the sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

TRANSMISSION BUSINESS LINE

By: /S/ ALLAN F PASCHKE

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: 8/6/02

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

POWER BUSINESS LINE

By: /S/ ANNE E DRAPER

Name: Anne E. Draper
Print/Type

Title: Manager, Transmission & Reserve Services

Date: 8 August 02

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery to the Nevada-Oregon Border (NOB)

1. TERM OF TRANSACTION

Start Date: at 2400 hours on June 30, 2000
Termination Date: 2400 hours on June 30, 2010

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
PBL – Various Resources	Big Eddy Substation	TBL	24 MW	NOB	LADWP	24 MW	Various receiving parties
Total Transmission Demand			24 MW			24 MW	

3. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

4. DESCRIPTION OF POINTS OF DELIVERY

Nevada-Oregon Border

Location: the point where the Government's 1,000 kV DC line crosses the

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[1] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.

Nevada/Oregon border;

Voltage: 1,000 kV;

Metering: quantities to be scheduled.

5. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLICATION**
Not applicable per section 1.12 of this MOA

6. **NAMES(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None

7. **SHORT DISTANCE DISCOUNT**
Not applicable

8. **ANCILLARY SERVICES PROVIDED**

(a) **Load Regulation**
Load Regulation is not required for this transaction.

(b) **Energy Imbalance**
Energy Imbalance is not required for this transaction.

(c) **Control Area Reserves for Resources Control Area Reserves for Resources are not required for this transaction.**
Control Area Reserves for Resources are not required for this transaction.

(d) **Control Area Reserves for Interruptible Purchases**
Control Area Reserves for Interruptible Purchases are not required for this transaction.

(e) **Transmission Losses**
Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

9. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom the sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

TRANSMISSION BUSINESS LINE

By: Allan F. Paschke

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: 6/14/00

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

POWER BUSINESS LINE

By: Anne E. Draper

Name: Anne E. Draper
Print/Type

Title: Manager,
Transmission Acquisition and Reserves

Date: 6/16/00

10-16-00A10:43 RCVD

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery at the Nevada-Oregon Border (NOB)

1. TERM OF TRANSACTION

Start Date: 2400 hours, June 1, 2003, subject to the payment of the reservation fee as noted below.
Termination Date: 2400 hours, May 31, 2005

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various receiving parties

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Los Angeles Department of Water & Power (LADWP)

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation	NOB, 500 kV	6/1/03 - 5/31/05: 150 MW	IS-96

Reservation Fee: The annual non-refundable reservation fee schedule shall be applied as follows: (1) $191,000 due and payable to TBL within 30 days of execution of this Table 51; (2) another $191,000 due and payable within 1 year and 30 days of the execution date of this Table 51; and (3) another $191,000 due and payable within 2 years and 30 days of execution of this table 51. TBL shall bill PBL within 30 days before the annual execution.

Scheduling: Firm transmission for 150 MW effective on the Effective Date as stated in Section 1 above.

6. DESCRIPTION OF POINTS OF INTERCONNECTION

BIG EDDY SUBSTATION

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

7. DESCRIPTION OF POINTS OF DELIVERY

NEVADA/OREGON BORDER (NOB) POINT OF DELIVERY

Location: the point where the Government's 500 kV DC line crosses the Nevada/Oregon border;

Voltage: 500 kV;

Metering: quantities to be scheduled.

8. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable per section 1.1.2 of this MOA

9. NAME (S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None

10. SHORT DISTANCE DISCOUNT

Not Applicable

11. ANCILLARY SERVICES

(a) Load Regulation

Load Regulation is provided by LADWP. Load Regulation is not required from the TBL for this transaction.

(b) Energy Imbalance

Provided under this Table 51.

(c) Control Area Reserves for Resources

Provided under this Table 51.

(d) Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are not required for this transaction.

(e) Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

BONNEVILLE POWER ADMINISTRATION
Transmission Business Line

By: _____

Name: Allan F. Paschke

Title: Transmission Account Executive

Date: 9/14/00

BONNEVILLE POWER ADMINISTRATION
Power Business Line

By: _____

Name: Anne E. Draper
(Print/Type)

Title: Acquisition and Reserve Services

Date: 10/13/00

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery at the Nevada-Oregon Border (NOB)

1. TERM OF TRANSACTION

Start Date: 2400 hours, March 31, 1997.
Termination Date: 2400 hours, March 31, 2017.

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various receiving parties.

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Los Angeles Department of Water & Power (LADWP)

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation, 500 kV	NOB, 500 kV	4/1/97-3/31/17: 300 MW	IS-96
		Total 300 MW	

6. DESCRIPTION OF POINTS OF INTERCONNECTION

BIG EDDY SUBSTATION

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

7. **DESCRIPTION OF POINTS OF DELIVERY**

NEVADA/OREGON BORDER (NOB) POINT OF DELIVERY

Location: the point where the Government's 500 kV DC line crosses the Nevada/Oregon border;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

8. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**

Not applicable per section 1.1.2 of this MOA.

9. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**

None.

10. **SHORT DISTANCE DISCOUNT**

Not Applicable.

11. **ANCILLARY SERVICES**

a. **Load Regulation**

Load Regulation is provided by LADWP.
Load Regulation is not required for this transaction.

b. **Energy Imbalance**

Energy Imbalance is provided pursuant to section 6(a) of the Index and General Specifications to this Exhibit C.

Energy Imbalance is not required for this transaction.

c. Control Area Reserves for Resources

Control Area Reserves for Resources are provided pursuant to section 6(a) of the Index and General Specifications to this Exhibit C.

Control Area Reserves for Resources are not required for this transaction.

d. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are not required for this transaction.

e. Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

AUTHENTICATED

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery to the Big Eddy Substation.

This revision reflects an election to exercise Right of First Refusal.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on October 1, 2004.
Termination Date: 0000 hours on October 1, 2005.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

2.1 OASIS Assignment Reference Number: 1321893

Delivering Party (Resource)	POI	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
Various Delivering Parties (Special Intertie Service)	Nevada-Oregon Border (NOB) 1000 kV	LADWP	100 MW	Big Eddy Substation 500 kV	TBL	100 MW	Various Receiving Parties (Special Intertie Service)
Total Transmission Demand			100 MW			100 MW	

3. DESCRIPTION OF POINT OF INTERCONNECTION

NEVADA - OREGON BORDER (NOB)

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where the Transmission Provider shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

4. DESCRIPTION OF POINT OF DELIVERY

BIG EDDY SUBSTATION

Location: The point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

5. MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED
100 MW.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION
Not applicable per section 1.12 of this MOA.

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE
None.

8. SERVICE UNDER THIS AGREEMENT WILL BE SUBJECT TO SOME COMBINATION OF THE CHARGES DETAILED BELOW. (THE APPROPRIATE CHARGES FOR TRANSACTIONS WILL BE DETERMINED IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE TARIFF.)

8.1 **Transmission Charge:**
PTP-04 Rate Schedule or Successor Rate Schedule.

8.1.1 **Reservation Fee:**
Not applicable.

8.1.2 **Short Distance Discount (SDD):**
Not applicable.

8.2 **System Impact and/or Facilities Study Charge(s):**
System Impact and/or Facilities Study Charges are not required for service under this Table 53.

8.3 **Direct Assignment and Use-of-Facilities Charges:**
Facilities Charges are not required at this time for the service under this Table 53.

8.4 **Ancillary Service Charges:**
ACS-04 Rate Schedule.

8.4.1 **Ancillary Services are provided as follows:**

	Ancillary Service	Provided By	Contract No.
8.4.1.1	Scheduling, System Control, and Dispatch	BPA (TBL)	96MS-95363
8.4.1.2	Reactive Supply and Voltage Control from Generation Sources	BPA (TBL)	96MS-95363
8.4.1.3	Regulation and Frequency Response	- -	- -
8.4.1.4	Energy Imbalance	- -	- -
8.4.1.5	Operating Reserve – Spinning Reserve	BPA (TBL) As Applicable	96MS-95363
8.4.1.6	Operating Reserve – Supplemental Reserve	BPA (TBL) As Applicable	96MS-95363

8.4.2 **Notification of Changes in Ancillary Services Provider:** Except for those Ancillary Services that must be provided by the Transmission Provider, the Transmission Customer may make an annual election to obtain some or all Ancillary Services from a third party or to self-supply Ancillary Services.

If the Transmission Customer intends that an entity other than the Transmission Provider provide any Ancillary Service for any Fiscal Year (October 1 through September 30), then the Transmission Customer must notify the Transmission Provider of its election of an Ancillary Service provider by July 1 of each Fiscal Year. Such election will be effective October 1 of the next Fiscal Year. If the Transmission Customer *does* make such election, the Transmission Provider will notify the Transmission Customer no later than September 1 of the Fiscal Year prior to the Fiscal Year for which such election is made, whether the Transmission Customer's alternative arrangements are comparable to purchasing the Ancillary Service(s) from the Transmission Provider, and are consistent with the Transmission Provider's business practices for self-supply or third party supply. In the event that, as to any Ancillary Service, the Transmission Customer's alternative arrangements are *not* comparable, or are inconsistent with the Transmission Provider's business practices for self-supply or third party supply, the Ancillary Service provider for such Ancillary Service for the next Fiscal Year shall be the Transmission Provider.

If the Transmission Customer does *not* elect to obtain any Ancillary Services from a third party or to self-supply any Ancillary Services, the Ancillary Service provider for the next Fiscal Year shall be the Transmission Provider.

9. OTHER PROVISIONS

In accordance with section 2.2 of the Open Access Transmission Tariff, the Transmission Customer has a reservation priority for the long-term firm transmission service provided under this Table 53. The Transmission Customer has elected to exercise such priority right with the Transmission Provider, by execution of this Table 53, to continue to take transmission service after September 30, 2004. If, due to the Celilo (DC Southern Intertie) Modernization Project, transmission is not available during some periods during the term of this revised Table, the Transmission Customer will, nevertheless, pay to the Transmission Provider each month the full long-term firm PTP transmission service charge based upon a demand of 100 MW, plus ancillary service and any other appropriate charges.

This obligation shall apply even if no transmission was available to the Transmission Customer for such month. This paragraph is not intended to affect the Transmission Customer's obligation to pay the full transmission service charge and other charges in the event transmission is unavailable for reasons other than the Celilo (DC Southern Intertie) Modernization Project.

10. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
TRANSMISSION BUSINESS LINE

By: **/S/ ALLAN F. PASCHKE**

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: **7/26/04**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
POWER BUSINESS LINE

By: **/S/ ANNE E. DRAPER**

Name: Anne E. Draper
Print/Type

Title: Manager,
Transmission Acquisition and Reserves

Date: **7/29/04**

AUTHENTICATED

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery to the Big Eddy Substation.

This revision reflects an election to exercise Right of First Refusal.

1. **TERM OF TRANSACTION**
Start Date: at 0000 hours on October 1, 2004.
Termination Date: 0000 hours on October 1, 2005.

2. **SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT**

2.1 OASIS Assignment Reference Number: 1321898

Delivering Party (Resource)	POI	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
Various Delivering Parties (Special Intertie Service)	Nevada-Oregon Border (NOB) 1000 kV	LADWP	100 MW	Big Eddy Substation 500 kV	TBL	100 MW	Various Receiving Parties (Special Intertie Service)
Total Transmission Demand			100 MW			100 MW	

3. **DESCRIPTION OF POINT OF INTERCONNECTION**

NEVADA - OREGON BORDER (NOB)

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where the Transmission Provider shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

4. DESCRIPTION OF POINT OF DELIVERY

BIG EDDY SUBSTATION

Location: The point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

5. MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED
100 MW.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION
Not applicable per section 1.12 of this MOA.

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE
None.

8. SERVICE UNDER THIS AGREEMENT WILL BE SUBJECT TO SOME COMBINATION OF THE CHARGES DETAILED BELOW. (THE APPROPRIATE CHARGES FOR TRANSACTIONS WILL BE DETERMINED IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE TARIFF.)

8.1 **Transmission Charge:**
PTP-04 Rate Schedule or Successor Rate Schedule.

8.1.1 **Reservation Fee:**
Not applicable.

8.1.2 **Short Distance Discount (SDD):**
Not applicable.

8.2 **System Impact and/or Facilities Study Charge(s):**
System Impact and/or Facilities Study Charges are not required for service under this Table 54.

8.3 **Direct Assignment and Use-of-Facilities Charges:**
Facilities Charges are not required at this time for the service under this Table 54.

8.4 **Ancillary Service Charges:**
ACS-04 Rate Schedule.

8.4.1 **Ancillary Services are provided as follows:**

	Ancillary Service	Provided By	Contract No.
8.4.1.1	Scheduling, System Control, and Dispatch	BPA (TBL)	96MS-95363
8.4.1.2	Reactive Supply and Voltage Control from Generation Sources	BPA (TBL)	96MS-95363
8.4.1.3	Regulation and Frequency Response	- -	- -
8.4.1.4	Energy Imbalance	- -	- -
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8.4.2 **Notification of Changes in Ancillary Services Provider:** Except for those Ancillary Services that must be provided by the Transmission Provider, the Transmission Customer may make an annual election to obtain some or all Ancillary Services from a third party or to self-supply Ancillary Services.

If the Transmission Customer intends that an entity other than the Transmission Provider provide any Ancillary Service for any Fiscal Year (October 1 through September 30), then the Transmission Customer must notify the Transmission Provider of its election of an Ancillary Service provider by July 1 of each Fiscal Year. Such election will be effective October 1 of the next Fiscal Year. If the Transmission Customer *does* make such election, the Transmission Provider will notify the Transmission Customer no later than September 1 of the Fiscal Year prior to the Fiscal Year for which such election is made, whether the Transmission Customer's alternative arrangements are comparable to purchasing the Ancillary Service(s) from the Transmission Provider, and are consistent with the Transmission Provider's business practices for self-supply or third party supply. In the event that, as to any Ancillary Service, the Transmission Customer's alternative arrangements are *not* comparable, or are inconsistent with the Transmission Provider's business practices for self-supply or third party supply, the Ancillary Service provider for such Ancillary Service for the next Fiscal Year shall be the Transmission Provider.

If the Transmission Customer does *not* elect to obtain any Ancillary Services from a third party or to self-supply any Ancillary Services, the Ancillary Service provider for the next Fiscal Year shall be the Transmission Provider.

9. OTHER PROVISIONS

In accordance with section 2.2 of the Open Access Transmission Tariff, the Transmission Customer has a reservation priority for the long-term firm transmission service provided under this Table 54. The Transmission Customer has elected to exercise such priority right with the Transmission Provider, by execution of this Table 54, to continue to take transmission service after September 30, 2004. If, due to the Celilo (DC Southern Intertie) Modernization Project, transmission is not available during some periods during the term of this revised Table, the Transmission Customer will, nevertheless, pay to the Transmission Provider each month the full long-term firm PTP transmission service charge based upon a demand of 100 MW, plus ancillary service and any other appropriate charges.

This obligation shall apply even if no transmission was available to the Transmission Customer for such month. This paragraph is not intended to affect the Transmission Customer's obligation to pay the full transmission service charge and other charges in the event transmission is unavailable for reasons other than the Celilo (DC Southern Intertie) Modernization Project.

10. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
TRANSMISSION BUSINESS LINE

By: **/S/ ALLAN F. PASCHKE**

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: **7/26/04**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
POWER BUSINESS LINE

By: **/S/ ANNE E. DRAPER**

Name: Anne E. Draper
Print/Type

Title: Manager,
Transmission Acquisition and Reserves

Date: **7/29/04**

AUTHENTICATED

Service Agreement No. 99TX-10251

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
BRITISH COLUMBIA POWER EXCHANGE CORPORATION

Index

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Exhibit A (Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit B (Facilities Charges)
Exhibit C (Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 31sr day of May, 1999, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and British Columbia Power Exchange Corporation (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 TERMS AND CONDITIONS

BPA agrees to provide and the Transmission Customer agrees to take and pay for PTP Transmission Services in accordance with the provisions of this Service Agreement and the Open Access Transmission Tariff (Tariff). The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this

reference. BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit A and made applicable to that transaction.

1.3 WHOLESALE POWER AND TRANSMISSION RATES SCHEDULES

BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated by this reference.

1.4 FACILITIES CHARGES

All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit B.

1.5 ANCILLARY SERVICES

The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit C.

1.6 TRANSMISSION SCHEDULING PROVISIONS

The Transmission Customer shall schedule transmission transactions in accordance with BPA's Transmission Scheduling Provisions and Procedures as posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPAT

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 2400 hours on June 12, 1999. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on June 12, 2004, or (b) 2400 hours on the date of termination established pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 CHARGES FOR TRANSMISSION SERVICE

The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the BPA Wholesale Power and Transmission Rate Schedules. BPA may change the rates that apply to Transmission Service under this Service Agreement pursuant to applicable law.

4.2 BILLING AND PAYMENT

Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and shall be payable in accordance with the Tariff.

4.3 BPA APPROPRIATIONS REFINANCING ACT, PUBLIC LAW 104-134

The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If to the Transmission Customer	If to BPA
Power Exchange Corporation (Powerex) Suite 1400 – 666 Burrard Street Vancouver B.C. V6C 2X8 Attention: Michelle Hiley Phone: (604) 891-5056 Fax: (604) 891-5022	Bonneville Power Administration P. O. Box 491 Vancouver, WA 98666-0491 Attention: Transmission Account Executive for Powerex Phone: (360) 418-2246 Fax: (360) 418-8320

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified Transmission Service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in

writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 INTERCONNECTION WITH OTHER SYSTEMS

Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 GOVERNING LAW

This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3 AMENDMENTS

Except as provided in Articles 1.1, 6.4, and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 TARIFF REVISIONS

In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than 60 days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within 30 days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within 30 days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the Transmission Service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.5 REVISION OF EXHIBITS

If any changes to Exhibits A, B, or C are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.5.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit a pursuant to this Service Agreement, BPA shall prepare a revised Exhibit A. BPA reserves the unilateral right to amend contiguous point of delivery provisions in Exhibit A of this Service Agreement.

6.5.2 If the Parties agree to change Exhibit B, BPA shall prepare a new Exhibit B. BPA reserves the right to revise Exhibit B annually to reflect changes consistent with the provisions of Exhibit B, section 1.

6.5.3 If the Parties agree to change Exhibit C, BPA shall prepare a new Exhibit C. BPA reserves the right to update the loss factors identified in Exhibit C, section 2, Transmission Loss Factors.

6.6 TEMPORARY LOAD SHIFTS AND MAINTENANCE NOTIFICATION

The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within 4 days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The point of contact for each Party will be designated pursuant to Article 5.2 of this Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within 4 days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.7 SEVERABILITY

In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service

Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.8 COMPUTATION OF TIME

To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.9 NO THIRD PARTY BENEFICIARIES

This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.10 WAIVERS

Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.11 SUCCESSORS AND ASSIGNS

This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.12 SERVICE AGREEMENT GOVERNS

In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.13 ENTIRE AGREEMENT

This Service Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

ARTICLE 7
SIGNATURES

The signatories represent that they are authorized to enter into this Service Agreement on behalf of the Party for whom they sign.

BRITISH COLUMBIA POWER EXCHANGE CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ CLIFFORD C. PERIGO
Name: Murray Margolis (Print/Type)	Name: Clifford C. Perigo (Print/Type)
Title: Head Trader	Title: Senior Transmission Account Executive
Date: 31 May 99	Date: 5-13-99

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Exhibit B
FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

1. USE-OF-FACILITIES COSTS FOR WHICH THE TRANSMISSION CUSTOMER IS RESPONSIBLE

(a) **Calculation of Charges Pursuant to the UFT-96 Rate Schedule**

Facility	Investment [1]	I&A Annual Cost Ratio [2]	I&A Annual Cost	O&M Annual Cost [3]	Sum of Non-Coincidental Demands	$/kW/yr
Substation	$	%	$	$		$
			Total UFT Charge =			$0./kW/mo
			kW to apply UFT charge to:			0 kW

(b) **Changes in Costs and Demands.** BPA may revise Exhibit B annually to reflect changes in: (1) the yearly noncoincidental demands on the facility under this Service Agreement and other agreements; (2) I&A annual cost ratios; (3) O&M annual costs; and (4) investments in facilities.

2. DIRECT ASSIGNMENT FACILITIES CHARGES

none

3. FORMER UFT FACILITIES

---

[1] 199X computation.
[2] Based on ACR table dated _____
[3] Based on O&M table dated _____

(W\TMC\CT\10251.DOC) 04/08/99

Exhibit C
ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL[1/])	99TX-10251
(b)	**Energy Imbalance**	n/a	
(c)	**Control Area Reserves for Resources**	n/a	
(d)	**Control Area Reserves for Interruptible Purchases**	n/a	
(e)	**Load Regulation**	n/a	
(f)	**Reactive Supply and Voltage Control**	BPA (TBL)	99TX-10251
(g)	**Transmission Losses**	Transmission Customer	See Section 5 below

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) **Transmission Losses Associated with Federal Power**
Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) **Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power**
The Transmission Customer shall compensate BPA for losses BPA incurs when providing Transmission Service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be determined by multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in section 2; and

[1/] BPA's Transmission Business Line.

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) **Transmission Losses Associated with Delivery Facilities** Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year [2/] pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) **Notification**

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice

[2/] Fiscal Year is defined as the twelve-month period from October 1 through September 30.

for compensating BPA for transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit C.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate in the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) **Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year**

The Transmission Customer has elected to return Transmission Losses for the period 2400 hours the Date of Execution, 1999, through 2400 hours September 30, 1999. The Transmission Customer will return the losses from a single Control Area in the Pacific Northwest, as defined in the Pacific Northwest Electric Power Planning and Conservation Act. The name of that Control Area is Powerex.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit C as appropriate, but not more frequently than once in a 12-month period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit C incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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Department of Energy

Bonneville Power Administration
P.O. Box 491
Vancouver, Washington 98666-0491

TRANSMISSION BUSINESS LINE

AUTHENTICATED
June 13, 2001

In reply refer to: TM/DITT2

Contract No. 99TX-10251
Amendatory Agreement No. 1

Mr. Murray Margolis, Head Trader
Powerex Corp.
Suite 1400, 666 Burrard Street
Vancouver, BC V6C 2X8
Canada

Dear Mr. Margolis:

This letter constitutes Amendment No. 1 (Amendment) to the Firm Point-to-Point Transmission Service Agreement, Contract No. 99TX-10251, (Service Agreement), between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (BPA), and Powerex Corp. (Transmission Customer).

This Amendment to the Service Agreement acknowledges the Parties' desire to extend the term of the Service Agreement to 2400 hours on June 30, 2021. The Parties agree that all other terms and conditions of the Agreement, as amended, remain the same. Article 3 of the Agreement is hereby amended to read as follows:

> "Service under this Service Agreement shall commence at 2400 hours on June 12, 1999. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on June 30, 2021; or (b) 2400 hours on the date of termination

established pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied."

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

Sincerely,

Senior Transmission Account Executive

Name Clifford C. Perigo
(Print/Type)

ACCEPTED:

POWEREX CORP.

By: /S/ M. MARGOLIS

Name: Murray Margolis
(Print/Type)

Title: Head Trader

Date: 5 July 01

EXECUTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ CLIFFORD C. PERIGO

Name: Clifford C. Perigo
(Print/Type)

Title: Transmission Account Executive

Effective Date: 7-5-01

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EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

REVISION NO. 4, TABLE 10
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 441996

This Revision No. 4 to Table 10 reflects an assignment of transmission service (see section 3) under this Service Agreement from Assignor Powerex (the Transmission Customer in this Table 10) to Assignee Hermiston Power Partnership (HPP)[1] and is contingent upon execution of such assignment. This Revision No. 4 to Table 10 decreases the Transmission Customer's transmission demand by 100 MW at the John Day Substation POI and the California-Oregon border POD beginning at 0000 hours on April 1, 2002. Such assignment terminates on 2400 hours, June 30, 2021.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on April 1, 2002.
Termination Date: the earlier of (a) 2400 hours on June 30, 2021; or (b) 2400 hours on the termination date established pursuant to Article 3 of this Service Agreement.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

AC Intertie Transmission							
Delivering Party (Resource) [2]	**POI Name & Voltage**	**POI Control Area**	**Maximum POI Demand (kW)**	**POD Name & Voltage**	**POD Control Area**	**Maximum POD Demand (kW)**	**Receiving Party**[2]
	John Day Substation (500 kV)	BPA	See §3 below	COB (500 kV)	CA ISO	See §3 below	Powerex or Designated Agent[3]
DC Intertie Transmission							
	Big Eddy Substation (500 kV)	BPA	See §3 below	NOB (1000 kV)	LDWP	See §3 below	Powerex or Designated Agent [3]

Total Reserved Capacity: See section 3 below.

[1] See Exhibit A, Revision No. 8, of the HPP Service Agreement, Contract No. 98TX-10154.

[2] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

AC Intertie

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	04/01/021 – 06/30/21: 0 MW	IS-02

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	04/01/021 – 06/30/21: 0 MW	IS-02

DC Intertie

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (500 kV)	NOB (1000 kV)	03/01/02 – 06/30/21: 0 MW	IS-02

4. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) **John Day Substation**

Location: the points in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

(b) **Big Eddy Substation**

Location: the points in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 230/500 kV.

5. POINTS OF DELIVERY

(a) **California-Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (ISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

(b) **Nevada-Oregon Border (NOB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border, where the Transmission Provider shall make electric power available for the Transmission Customer hereunder;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

BRITISH COLUMBIA POWER EXCHANGE CORPORATION

By: /S/ DANNY O'HEARN

Name: **Dan O'Hearn**
(Print/Type)

Title: **Portfolio Manager**

Date: **February 26, 2002**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ ROBERT LAHMANN for

Name: Clifford C. Perigo
(Print/Type)

Title: Senior Transmission Account Executive

Date: **3/1/02**

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AUTHENTICATED EXHIBIT A, TABLE 21

REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 386964

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: at 0000 hours on January 1, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	John Day Substation (500 kV)	BPA	See Sect. 3 Below	COB (500 kV)	CA ISO[2]	See Sect. 3 Below	Powerex or Designated Agent[3]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	01/01/05 – 01/01/06 (42 MW)	IS-02

4. DESCRIPTION OF POINT OF INTERCONNECTION

John Day Substation

Location: the points in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

---

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] California (CA) Independent System Operator (ISO).

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to the Transmission Provider's Transmission Scheduling Provisions.

5. **POINT OF DELIVERY**

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (ISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

IN WITNESS WHEREOF, the Parties have caused this Revision to the Service Agreement to be executed by their respective authorized officials.

BRITISH COLUMBIA POWER EXCHANGE CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ ANTONY T RODRIGUES
Name: Murray Margolis *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
Title: Head Trader	Title: Senior Transmission Account Executive
Date: 6 Jun 03	Date: June 6, 2003

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AUTHENTICATED EXHIBIT A, TABLE 24

REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 786743

1. TERM OF TRANSACTION

Start Date: at 0000 hours on September 1, 2003.
Termination Date: on 0000 hours on September 1, 2006.

This term matches the duration of a competing request that extends through April 1, 2006, and allows the contract to be extended in annual increments. Table 24 combines and replaces Table 12, Table 13 and Table 15, effective September 1, 2002, through September 1, 2003, and extends their termination date. This extension of service is available pursuant to Section 2.2, Reservation Priority for Existing Firm Service Customers, of the Open Access Transmission Tariff (OATT), effective October 1, 2001, which requires that:

> Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	John Day Substation (500 kV)	BPA	See Sect. 3 Below	COB (500 kV)	CA ISO[2]	See Sect. 3 Below	Powerex or Designated Agent[3]

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] California (CA) Independent System Operator (ISO).

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to the Transmission Provider's Transmission Scheduling Provisions.

Total Reserved Capacity	See Sect. 3 Below	See Sect. 3 Below

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	09/01/03 – 9/01/06 (336 MW)	IS-02

The combined capacity demands from Table 12 (200 MW), Table 13 (63 MW), and Table 15 (73 MW) equal 336 MW.

4. DESCRIPTION OF POINT OF INTERCONNECTION

John Day Substation

Location: the points in the Transmission Provider's John Day Substation, where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. POINT OF DELIVERY

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (ISO) hereunder;
Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWEREX CORP. UNITED STATES OF AMERICA

Department of Energy
Bonneville Power Administration

By:	/S/ DOUGLAS LITTLE	By:	/S/ NANCY E MORGAN for
Name: *(Print/Type)*	Douglas Little	Name: *(Print/Type)*	Antony T. Rodrigues
Title:	V.P. Marketing & Trade Policy	Title:	Senior Transmission Account Executive
Date:	Aug 5/03	Date:	7-25-03

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 25
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 825197

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: on 0000 hours on January 1, 2006.

The Transmission Customer and the Transmission Provider agree to the following conditions:

(a) Amendment No. 1 to Agreement No. 99TX-10230 and Revision No. 1 to Exhibit A of the Agreement: The Transmission Customer shall execute Amendment No. 1 to Agreement No. 99TX-10230 (Agreement) and Revision No. 1 to Exhibit A of the Agreement, which extend the termination date of the Agreement from August 31, 2003, to August 31, 2004, and designate 194 MW as the amount of reservation priority (rollover) rights available under the Agreement. Furthermore, the Transmission Customer agrees to waive its reservation priority (rollover) rights.

(b) Reservation Priority (Rollover) Rights for Table 4a to Exhibit A of Agreement No. 99TX-10251: The Transmission Customer agrees that Table 4a to Agreement No. 99TX-10251 does not have reservation priority (rollover) rights as described in Section 2.2 of the Open Access Transmission Tariff, pursuant to Section 3.2 of the TR-02/TC-02 Settlement Agreement, dated June 20, 2000.

(c) Table 22 and Table 23 to Exhibit A of Agreement No. 99TX-10251: The Transmission Customer shall unconditionally reject the offers for transmission service made by the Transmission Provider in Table 22 and Table 23 to Agreement 99TX-10251, dated June 30, 2003. The Transmission Provider will remove in their entirety from the long-term queue both of the Transmission Customer's requests, which were assigned OASIS Queue No. 664 and OASIS Queue No. 665, respectively, for the service from Big Eddy to Nevada-Oregon Border (NOB) associated with these offers.

(d) Transmission Requests, OASIS Queue Nos. 658, 663, 667, 668, 670, and 671: The Transmission Customer shall withdraw the following transmission requests for service from Big Eddy to NOB: OASIS Queue Nos. 658, 663, 667, 668, 670, and 671.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	01/01/05 – 01/01/06 408 MW	IS-02

Remainder of 1,000 MW Request: The maximum capacity requested is 1,000 MW, and due to insufficient capacity the transmission demand under this Table 25 is limited to 408 MW. The remainder of the capacity of 592 MW will remain in the queue until December 31, 2005.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

---

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

5. **POINTS OF DELIVERY**

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ ANTONY RODRIGUES
Name: **Murray Margolis** *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
Title: **Head Trader**	Title: Senior Transmission Account Executive
Date: **Sep 10, 2003**	Date: **August 22, 2003**

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 26
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 825204

1. TERM OF TRANSACTION

Start Date: at 0000 hours on June 1, 2005.
Termination Date: on 0000 hours on June 1, 2006.

The Transmission Customer and the Transmission Provider agree to the following conditions:

(a) Table 25 to Exhibit A of Agreement No. 99TX-10251: The Transmission Customer shall execute Table 25 to Exhibit A of Agreement No. 99TX-10251, and agree to the terms and conditions included therein.

(b) Transmission Request, OASIS Queue No. 672-01: The Transmission Customer shall withdraw its transmission request for service from Big Eddy to NOB, which was assigned OASIS Queue No. 672-01.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	06/01/05 – 06/01/06 150 MW	IS-02

Remainder of 1,000 MW Request: The maximum capacity requested is 1,000 MW, and due to insufficient capacity the transmission demand under this Table 26 is limited to 100 MW. The remainder of the capacity of 850 MW will remain in the queue until May 31, 2006.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ ANTONY T RODRIGUES
Name: Murray Margolis *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
Title: Head Trader	Title: Senior Transmission Account Executive
Date: Sep 10, 2003	Date: August 22, 2003

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE
TABLE 29
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 885874

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: on 0000 hours on January 1, 2006.

The Transmission Customer and the Transmission Provider agree to the following condition:

Revision No. 2, Table 17 to Exhibit A of Agreement No. 99TX-10251: Prior to executing Table 29, the Transmission Customer shall execute Revision No. 2, Table 17 to Exhibit A of Agreement No. 99TX-10251.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	01/01/05 – 01/01/06 49 MW	IS-02

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

Remainder of 1,000 MW Request: The maximum capacity requested under Oasis Request No. 672 is 1,000 MW. Due to insufficient capacity, a partial award of 408 MW was made under Table 25, and the transmission demand under this Table 29 is limited to 49 MW. The remainder of the capacity of 543 MW will remain in the queue, unless awarded, until January 2, 2005.

4. **DESCRIPTION OF POINTS OF INTERCONNECTION**

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

5. **POINTS OF DELIVERY**

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

POWEREX CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ THOMAS M NOGUCHI
Name: Murray Margolis *(Print/Type)*	Name: Thomas M. Noguchi *(Print/Type)*
Title: Head Trader	Title: Senior Transmission Account Executive
Date: 29 Oct 03	Date: 10/16/03

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EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 40
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1349205.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on June 1, 2005.
Termination Date: at 0000 hours on June 1, 2007.

The Transmission Provider's offer of transmission service to the Transmission Customer under this Table 40 in Exhibit A to Service Agreement No. 99TX-10251 (Service Agreement) is contingent upon the choice the Transmission Customer makes with regard to its section 2.2 reservation priority (rollover) rights associated with Table 32, which is also under this Service Agreement. These reservation priority rights are provided for in the Transmission Provider's Open Access Transmission Tariff.

If the Transmission Customer agrees to accept a contract term for the rollover of Table 32 that is at least equal to the term in this Table 40, then this Table 40 will be null and void.

If the Transmission Customer refuses to accept a contract term for the rollover of Table 32 that is at least equal to the term in this Table 40, or permanently releases capacity sufficient to provide for the transmission service in this Table 40, then Table 40 will be fully operational as of its effective date of June 1, 2005.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY.

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	06/01/05 – 06/01/07 250 MW	IS-04

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ NANCY E MORGAN
Name: Murray Margolis *(Print/Type)*	Name: Nancy E. Morgan *(Print/Type)*
Title: Head Trader	Title: Acting Transmission Sales Manager
Date: 17 Nov 04	Date: 11-1-04

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 41
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1356130.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: at 0000 hours on January 1, 2007.

This term is extended to match the duration of a competing request whose term runs for two years. This extension of the term of service is required pursuant to Section 2.2, Reservation Priority for Existing Firm Service Customers, of the Open Access Transmission Tariff (OATT), effective October 1, 2001, which provides that:

> Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	01/01/05 – 01/01/07 650 MW	IS-04

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

5. **POINTS OF DELIVERY**

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ DOUGLAS LITTLE	By: /S/ NANCY E MORGAN
Name: Douglas Little *(Print/Type)*	Name: Nancy E. Morgan *(Print/Type)*
Title: V.P. Marketing & Trade Policy	Title: Acting Transmission Sales Manager
Date: Dec 1/04	Date: 11-19-04

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 43
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1400275

1. TERM OF TRANSACTION

Start Date: at 0000 hours on March 1, 2005.
Termination Date: at 0000 hours on July 1, 2006.

This is an award of partial service, since as of the execution date of this Agreement, the Transmission Provider does not have sufficient transmission capacity to accommodate Point-to-Point Transmission Service to the Transmission Customer beyond the Termination Date. Therefore, the Transmission Customer shall not have the right defined in section 2.2 of the Tariff, to continue to take Point-to-Point Transmission Service from the Transmission Provider after the Termination Date listed above.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	John Day Substation (500 kV)	BPA	See Sect. 3 Below	COB (500 kV)	CAISO [2]	See Sect. 3 Below	Powerex or Designated Agent[3]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] California Independent System Operator (CAISO)

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	03/01/05 – 07/01/06 50 MW	IS-04

Remainder of 100 MW Request: The maximum capacity requested under Oasis Request No. 800 is 100 MW, starting on January 1, 2005, and ending on January 1, 2009. Due to insufficient capacity the transmission demand under this Table 43 is limited to 50 MW, and only for the period commencing on March 1, 2005, and terminating on July 1, 2006. The partial capacity award of 50 MW will be reinstated to the OASIS Long-Term Queue on July 2, 2006.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

John Day Substation

Location: the points in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (CAISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWEREX CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ DAVID A FITZSIMMONS
Name: **Murray Margolis** *(Print/Type)*	Name: David A. Fitzsimmons *(Print/Type)*
Title: **Head Trader**	Title: Transmission Account Executive
Date: **2/17/05**	Date: **2/3/05**

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COB to John Day Summary

AC COB S>N 2005		Contract Number	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180
	TPU	DE-MS79-94BP94524	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17
	SNO	DE-MS79-94BP94525	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17
	PSE	DE-MS79-94BP94521	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167
	SCL	DE-MS79-94BP94522	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67
	PRC	DE-MS79-94BP94523	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21

COB to John Day Summary

AC COB S>N 2005		Contract Number	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221
	TPU	DE-MS79-94BP94524	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21
	SNO	DE-MS79-94BP94525	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21
	PSE	DE-MS79-94BP94521	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204
	SCL	DE-MS79-94BP94522	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82
	PRC	DE-MS79-94BP94523	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221
	TPU	DE-MS79-94BP94524	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21
	SNO	DE-MS79-94BP94525	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21
	PSE	DE-MS79-94BP94521	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204
	SCL	DE-MS79-94BP94522	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82
	PRC	DE-MS79-94BP94523	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221
	TPU	DE-MS79-94BP94524	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21
	SNO	DE-MS79-94BP94525	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21
	PSE	DE-MS79-94BP94521	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204
	SCL	DE-MS79-94BP94522	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82
	PRC	DE-MS79-94BP94523	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15
AC Intertie																												
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
AC Participants																												
	PGE	DE-MS79-87BP92340	434	434	434	354	354	354	434	434	434	434	434	434	434	434	434	354	354	354	434	434	434	434	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	221	221	180	180	180	221	221	221	221	221	221	221	221	221	180	180	180	221	221	221	221	221	221	221	221
	TPU	DE-MS79-94BP94524	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21
	SNO	DE-MS79-94BP94525	21	21	21	17	17	17	21	21	21	21	21	21	21	21	21	17	17	17	21	21	21	21	21	21	21	21
	PSE	DE-MS79-94BP94521	204	204	204	167	167	167	204	204	204	204	204	204	204	204	204	167	167	167	204	204	204	204	204	204	204	204
	SCL	DE-MS79-94BP94522	82	82	82	67	67	67	82	82	82	82	82	82	82	82	82	67	67	67	82	82	82	82	82	82	82	82
	PRC	DE-MS79-94BP94523	25	25	25	21	21	21	25	25	25	25	25	25	25	25	25	21	21	21	25	25	25	25	25	25	25	25

COB to John Day Summary

AC COB S>N 2005		Contract Number	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
AC Intertie													
	PacifiCorp	DE-MS79-94BP94285	71	71	71	71	71	71	71	71	71	71	71
AC Participants													
	PGE	DE-MS79-87BP92340	434	354	354	354	434	434	434	434	434	434	434
	PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	221	180	180	180	221	221	221	221	221	221	221
	TPU	DE-MS79-94BP94524	21	17	17	17	21	21	21	21	21	21	21
	SNO	DE-MS79-94BP94525	21	17	17	17	21	21	21	21	21	21	21
	PSE	DE-MS79-94BP94521	204	167	167	167	204	204	204	204	204	204	204
	SCL	DE-MS79-94BP94522	82	67	67	67	82	82	82	82	82	82	82
	PRC	DE-MS79-94BP94523	25	21	21	21	25	25	25	25	25	25	25

Big Eddy to NOB

DC NOB N>S 2005

	Contract Number	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
Burbank	DE-MS79-87BP92411	20	20	20	20	40	40	40	40	40	40	20	20	20	20	20	20	40	40	40	40	40	40	20	20	20	20	20	40	40
Glendale	DE-MS79-87BP92412	10	10	10	10	20	20	20	20	20	20	10	10	10	10	10	10	20	20	20	20	20	20	10	10	10	10	10	20	20
Pasadena	DE-MS79-87BP92413	6	6	6	6	12	12	12	12	12	12	6	6	6	6	6	6	12	12	12	12	12	12	6	6	6	6	6	6	12	12
Pasadena	DE-MS79-94BP93658					15	15	15	15	15								15	15	15	15	15								15	15
Riverside	DE-MS79-90BP92858	16	16	16	16	23	23	23	23	23	23	16	16	16	16	16	16	23	23	23	23	23	23	16	16	16	16	16	16	23	23
Riverside	DE-MS79-94BP93958	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60
PBL (Table 50)	96MS-95363	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100									
Hermiston, Calpine	98TX-10154			228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650						
Powerex Corp	99TX-10251	408	408	408	408	408	408	408	408	408	408	408	408																		
Powerex Corp	99TX-10251	49	49	49	49	49	49	49	49	49	49	49	49																		
Powerex Corp	99TX-10251						150	150	150	150	150	150	150	150	150	150	150	150													
Powerex Corp	99TX-10251	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Morgan Stanley	97TX-10031 Ex C Table 16	50	50	50	50	50	50	50	50	50	50	50	50																		
Morgan Stanley	97TX-10031 Ex C Table 17	50	50	50	50	50	50	50	50	50	50	50	50																		
Morgan Stanley	97TX-10031 Ex C Table 18													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Morgan Stanley	97TX-10031 Ex C Table 19													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Coral Power	00TX-10286 Table 3													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Coral Power	00TX-10286 Table 4													50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Idaho Power Company	DE-MS79-91BP93094	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005

	Contract Number	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Burbank	DE-MS79-87BP92411	40	40	40	40	20	20	20	20	20	20																				
Glendale	DE-MS79-87BP92412	20	20	20	20	10	10	10	10	10	10																				
Pasadena	DE-MS79-87BP92413	12	12	12	12	6	6	6	6	6	6																				
Pasadena	DE-MS79-94BP93658	15	15	15								15	15	15	15	15								15	15	15	15	15			
Riverside	DE-MS79-90BP92858	23	23	23	23	16	16	16	16	16	16	23	23	23	23	23	23	16	16	16	16	16	16	23	23	23	23	23	23	16	16
Riverside	DE-MS79-94BP93958	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15
PBL (Table 50)	96MS-95363	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172																														
Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251	200	200	200	200	200	200	200	200	200	200	200	200	200	200																
Morgan Stanley	97TX-10031 Ex C Table 16																														
Morgan Stanley	97TX-10031 Ex C Table 17																														
Morgan Stanley	97TX-10031 Ex C Table 18	50	50	50	50	50	50																								
Morgan Stanley	97TX-10031 Ex C Table 19	50	50	50	50	50	50																								
Coral Power	00TX-10286 Table 3	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Coral Power	00TX-10286 Table 4	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Idaho Power Company	DE-MS79-91BP93094	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005

	Contract Number	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
Burbank	DE-MS79-87BP92411																														
Glendale	DE-MS79-87BP92412																														
Pasadena	DE-MS79-87BP92413																														
Pasadena	DE-MS79-94BP93658					15	15	15	15	15								15	15	15	15	15								15	15
Riverside	DE-MS79-90BP92858	16	16	16	16	23	23																								
Riverside	DE-MS79-94BP93958	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60
PBL (Table 50)	96MS-95363	24	24	24	24	24	24																								
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172																														
Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Morgan Stanley	97TX-10031 Ex C Table 16																														
Morgan Stanley	97TX-10031 Ex C Table 17																														
Morgan Stanley	97TX-10031 Ex C Table 18																														
Morgan Stanley	97TX-10031 Ex C Table 19																														
Coral Power	00TX-10286 Table 3																														
Coral Power	00TX-10286 Table 4																														
Idaho Power Company	DE-MS79-91BP93094	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3											
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005	Contract Number	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Burbank	DE-MS79-87BP92411																														
Glendale	DE-MS79-87BP92412																														
Pasadena	DE-MS79-87BP92413																														
Pasadena	DE-MS79-94BP93658	15	15	15								15	15	15	15	15								15	15	15	15	15			
Riverside	DE-MS79-90BP92858																														
Riverside	DE-MS79-94BP93958	60	60	60	60	15	15	15	15	15	15	60	60	60	60	60	60	15	15	15	15	15	15	60	60	60	60				
PBL (Table 50)	96MS-95363																														
PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TransAlta	98TX-10172																														
Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Powerex Corp	99TX-10251																														
Morgan Stanley	97TX-10031 Ex C Table 16																														
Morgan Stanley	97TX-10031 Ex C Table 17																														
Morgan Stanley	97TX-10031 Ex C Table 18																														
Morgan Stanley	97TX-10031 Ex C Table 19																														
Coral Power	00TX-10286 Table 3																														
Coral Power	00TX-10286 Table 4																														
Idaho Power Company	DE-MS79-91BP93094																														
PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Big Eddy to NOB

DC NOB N>S 2005																						
		Contract Number	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
	Burbank	DE-MS79-87BP92411																					
	Glendale	DE-MS79-87BP92412																					
	Pasadena	DE-MS79-87BP92413																					
	Pasadena	DE-MS79-94BP93658																					
	Riverside	DE-MS79-90BP92858																					
	Riverside	DE-MS79-94BP93958																					
	PBL (Table 50)	96MS-95363																					
	PBL (Table 18)	96MS-95363	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
	TransAlta	98TX-10172																					
	Hermiston, Calpine	98TX-10154	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Powerex Corp	99TX-10251																					
	Morgan Stanley	97TX-10031 Ex C Table 16																					
	Morgan Stanley	97TX-10031 Ex C Table 17																					
	Morgan Stanley	97TX-10031 Ex C Table 18																					
	Morgan Stanley	97TX-10031 Ex C Table 19																					
	Coral Power	00TX-10286 Table 3																					
	Coral Power	00TX-10286 Table 4																					
	Idaho Power Company	DE-MS79-91BP93094																					
	PGE AC/DC Exchange	DE-MS79-87BP92340	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

John Day to COB Summary

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	Contract Number	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	486	486	258	258	258	258	258	258	258	258	258
PowerEx(What happened to Table 43?)	99TX-10251	0	0	50	50	50	50	50	50	50	50	50
PowerEx	99TX-10251	200	200	200	200	200	200	200	200	200	200	200
PowerEx	99TX-10251	63	63	63	63	63	63	63	63	63	63	63
PowerEx	99TX-10251	73	73	73	73	73	73	73	73	73	73	73
PowerEx	99TX-10251	42	42	42	42	42	42	42	42	42	42	42
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1	95	95	95	95	95	95	95	95	95	95	95
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5							100	100	100	100	100
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A	50	50	50	50	50	50	50	50	50	50	50
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882	20	20	20	20	20	20	20	20	20	20	20
TransCanada Power	02TX-10882	30	30	30	30	30	30	30	30	30	30	30
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	753	753	753	753	753	753	753	753	753	753	753
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	383	383	383	383	383	383	383	383	383	383	383
TCL	DE-MS79-94BP94524	36	36	36	36	36	36	36	36	36	36	36
SNO	DE-MS79-94BP94525	37	37	37	37	37	37	37	37	37	37	37
PSP&L	DE-MS79-94BP94521	354	354	354	354	354	354	354	354	354	354	354
SCL	DE-MS79-94BP94522	142	142	142	142	142	142	142	142	142	142	142
PNGC	DE-MS79-94BP94523	44	44	44	44	44	44	44	44	44	44	44

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	Contract Number	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	258	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	50	50	50	50	50	50	50	0	0	0	0
PowerEx	99TX-10251	200	200	200	200	200	200	200	200	200		
PowerEx	99TX-10251	63	63	63	63	63	63	63	63	63		
PowerEx	99TX-10251	73	73	73	73	73	73	73	73	73		
PowerEx	99TX-10251	42										
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1	95	95	95	95	95	95	95	95	95	95	95
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5	100	100	100	100	100	100	100				
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8		75	75	75	75	75	75	75	75	75	75
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9		42	42	42	42	42	42	42	42	42	42
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A	50										
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A		8	8	8	8	8	8	8	8	8	8
TransCanada Power	02TX-10882	20	20	20	20							
TransCanada Power	02TX-10882	30	30	30	30							
Transalta Energy	98TX-10172								42	42	42	42
PGE	DE-MS79-87BP92340	753	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	383	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	36	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	37	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	354	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	142	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	44	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1	95	95	95	95	95	95					
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8	75	75									
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9	42	42									
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A	8	8									
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172	42	42	42	42	42	42	42	42			
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180	180	180	180	180	180	180	180
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

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	Contract Number	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12	180	180	180	180							
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150	150	150	150	150	150	150	150	150	150	150
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363	150										
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363											
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
PBL	96MS-95363	50	50	50	50	50	50	50	50	50	50	50
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363											
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
PowerEx	99TX-10251											
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1											
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12											
PacifiCorp Power Mkting	00TX-10367 Table 5											
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8											
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9											
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A											
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A											
TransCanada Power	02TX-10882											
TransCanada Power	02TX-10882											
Transalta Energy	98TX-10172											
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45	45	45

John Day to COB Summary

AC COB N>S 2005

	Contract Number	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
PBL	96MS-95363	50	50	50	50	50	50			
PBLTable 17	96MS-95363	700	700	700	700	700	700	700	700	700
PBL Table 21	96MS-95363									
Hermiston, Calpine	98TX-10154	308	308	308	308	308	308	308	308	308
PowerEx(What happened to Table 43?)	99TX-10251	0	0	0	0	0	0	0	0	0
PowerEx	99TX-10251									
PowerEx	99TX-10251									
PowerEx	99TX-10251									
PowerEx	99TX-10251									
City of Klamath Falls Co-Gen Project	99TX-10204	280	280	280	280	280	280	280	280	280
Pacificorp (Kfalls)	00TX-10367, Table 1									
Pacificorp Power Mkting(Kfalls)	00TX-10367, Table 12									
PacifiCorp Power Mkting	00TX-10367 Table 5									
PacifiCorp Power Mkting	00TX-10367, Exhibit A Table 8									
PacifiCorp	DE-MS79-94BP94285	93	93	93	93	93	93	93	93	93
PacificCorp Power Mkting	00TX-10367 Exhibit A, Table 9									
PacificCorp Power Mkting	00TX-10367 Exhibit 11 Exhibit A									
PacificCorp Power Mkting	00TX-10367 Exhibit 10 Exhibit A									
TransCanada Power	02TX-10882									
TransCanada Power	02TX-10882									
Transalta Energy	98TX-10172									
PGE	DE-MS79-87BP92340	768	768	768	768	768	768	768	768	768
PacifiCorp	DE-MS79-95BP94628, DE-MS79-94BP94332	390	390	390	390	390	390	390	390	390
TCL	DE-MS79-94BP94524	37	37	37	37	37	37	37	37	37
SNO	DE-MS79-94BP94525	38	38	38	38	38	38	38	38	38
PSP&L	DE-MS79-94BP94521	361	361	361	361	361	361	361	361	361
SCL	DE-MS79-94BP94522	145	145	145	145	145	145	145	145	145
PNGC	DE-MS79-94BP94523	45	45	45	45	45	45	45	45	45

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

SEP 26 1994

In reply refer to: PMT

Amendatory Agreement No. 1
Contract No. DE-MS79-94BP94525

Mr. John F. Spencer
General Manager
Public Utility District No. 1 of
Snohomish County, Washington
2320 California Street
Everett, WA 98201

Dear Mr. Spencer:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and Public Utility District No. 1 of Snohomish County Washington (Snohomish), a municipal corporation operating and existing under the laws of the State of Washington, to amend Contract No. DE-MS79-94BP94525 (Capacity Ownership Agreement), executed by Snohomish on September 23, 1994. This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and Snohomish agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) Snohomish may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Snohomish. Snohomish agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to Snohomish under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) Snohomish hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. Snohomish does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but

not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to Snohomish consistent with the above.

Snohomish and Bonneville agree to negotiate in good faith the terms and conditions under which Snohomish shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Snohomish or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only Snohomish)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to Snohomish shall mean Snohomish or its designee. Any such designee shall be identified in writing by Snohomish to Bonneville. Only one entity may submit schedules on Snohomish's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to Snohomish, please sign and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Walter E. Pollock
Group Vice President, Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY

By _____

Name Mark A. Schinman
(Print/Type)

Title Deputy General Manager

Date October 25, 1994

Effective Date October 25, 1994

(PMLAN-W:\PMT\CONTRACT\LTR_AGMT\94525AM1.DOC)

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94525

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

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This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY WASHINGTON (Snohomish), a municipal corporation operating and existing under the laws of the state of Washington. Each of Bonneville and Snohomish is sometimes referred to individually in this Agreement as "Party"; Bonneville and Snohomish are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Seattle executed a Memorandum of Understanding, DE-MS79-92BP93479, dated September 18, 1991, which, among other things, sets forth the principles for Snohomish's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Snohomish are executing Contract No. DE-MS79-94BP93999 to provide Snohomish with, among other things, network wheeling between the John Day Substation and Snohomish's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Snohomish agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Snohomish's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this

Agreement, entered into by each Capacity Owner (other than Snohomish) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by Capacity Owners (other than Snohomish) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Snohomish pursuant to this Agreement, which percentage is determined by dividing Snohomish's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Snohomish pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Snohomish pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective

Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for

Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Snohomish's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Snohomish to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Snohomish.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1)

simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Snohomish for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Snohomish for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Snohomish's Capacity

Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement, interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Snohomish pursuant to this Agreement, which percentage is determined by dividing Snohomish's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Snohomish's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Snohomish.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Snohomish until payment is made by Snohomish pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Snohomish pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Snohomish written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and

obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Snohomish pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Snohomish, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Snohomish purchases from Bonneville and Bonneville sells to Snohomish the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, Snohomish shall notify Bonneville in writing of Snohomish's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Snohomish shall have the right to utilize its Scheduling Share pursuant to the paragraph Snohomish elects. Prior to Bonneville's receipt of such notification, Snohomish shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Snohomish fails to make an election within the prescribed time period, Snohomish shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Snohomish shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Snohomish does not own at the California-Oregon border or for which transmission Snohomish receives any revenue that would be reportable in Snohomish's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Snohomish's Scheduling Share is not fully utilized by Snohomish in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Snohomish's Scheduling Share for such hour but no longer than such hour. Snohomish shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Snohomish's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Snohomish has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Snohomish's Scheduling Share. In return for Snohomish's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Snohomish

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A,

or its successor to other entities in such hour, and (2) the ratio of Snohomish's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Snohomish's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Snohomish's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC

Intertie Operational Transfer Capability such that Snohomish's Scheduling Share for such hour is less than the MW amount of the aggregate of Snohomish's net firm transactions identified by Snohomish to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Snohomish's firm transactions that equals the difference between Snohomish's Scheduling Share for such hour and the MW amount of the aggregate of Snohomish's firm transactions for such hour up to, but not in excess of, Snohomish's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Snohomish is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Snohomish shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Snohomish pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for

Bonneville's firm power and energy sales and exchange transactions

(iii) Bonneville shall not be obligated to provide such wheeling to Snohomish pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Snohomish or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Snohomish shall identify such firm transaction to Bonneville. Snohomish shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Snohomish's contract for such firm transaction (after information considered proprietary by Snohomish has been redacted by Snohomish). Bonneville shall review such contract to verify that the transaction is firm. If Snohomish and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Snohomish retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Snohomish may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Snohomish. Snohomish shall have no obligation under this Agreement to make available to Bonneville any portion of Snohomish's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Snohomish's Scheduling Share without Snohomish's prior consent.

(B) Snohomish hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Snohomish with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Snohomish shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Snohomish uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Snohomish (and only Snohomish) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Snohomish's Scheduling Share for such hour. The MW amount of Snohomish's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Snohomish's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Snohomish shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Snohomish on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Snohomish of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Snohomish no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Snohomish no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Snohomish shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Snohomish shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Snohomish shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts"

shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Snohomish's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Snohomish's schedule exceeds Snohomish's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Snohomish information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Snohomish in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Snohomish's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Snohomish's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Snohomish may elect to acquire a share of such Upgrade in an amount up to Snohomish's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Snohomish shall notify Bonneville in writing of Snohomish's decision regarding such acquisition. If Snohomish elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Snohomish's notice to Bonneville shall include the percentage of such Upgrade that Snohomish elects to acquire (Acquisition Percentage). If Snohomish fails to notify Bonneville within such 100-day period, Snohomish shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Snohomish elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Snohomish shall be Snohomish's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Snohomish shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Snohomish's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Snohomish and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Snohomish and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Snohomish may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Snohomish such portion of the Unacquired Share as has been apportioned to Snohomish pursuant to the Apportionment, and Bonneville shall offer to Snohomish such portion of the Unacquired Share.

(2) If Bonneville does not receive from Snohomish and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Snohomish and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = (A ÷ B) x C

where: A = Snohomish's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Snohomish's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Snohomish shall notify Bonneville in writing of Snohomish's decision regarding acquisition of the Additional Share Offered. If Snohomish fails to notify Bonneville within such 30-day period, Snohomish shall be deemed to have elected not to acquire any of the Additional Share Offered. If Snohomish elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Snohomish shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Snohomish elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Snohomish with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Snohomish pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Snohomish shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Snohomish has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Snohomish's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Snohomish's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Snohomish to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Snohomish in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Snohomish to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Snohomish's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Snohomish of the entire Agreement and of all of Snohomish's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Snohomish of this Agreement or of any of Snohomish's rights under this Agreement as security for any indebtedness, whether present or future, of Snohomish pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Snohomish and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Snohomish has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Snohomish shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Snohomish transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Snohomish shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Snohomish's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Snohomish in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Snohomish in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time

during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Snohomish's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Snohomish based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Snohomish have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Snohomish pursuant to this subsection 7(d) shall not be payable by Snohomish pursuant to this Agreement.

(e) Bonneville shall provide Snohomish notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on Snohomish's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Snohomish's interests to the extent such interests have been expressed to Bonneville in writing.

8. **EXISTING AGREEMENTS**

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Snohomish's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Snohomish's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Snohomish's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Snohomish hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. **PAYMENT PROVISIONS**

As full compensation for their respective payment obligations under this Agreement, Snohomish shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Snohomish in accordance with the provisions of this section 9.

(a) **Lump Sum Payment**

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Snohomish for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as

described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Snohomish shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Snohomish agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Snohomish, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Snohomish shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may

mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Snohomish, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Snohomish agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Snohomish pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Snohomish pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville,

Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Snohomish a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Snohomish shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect

to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Snohomish, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Snohomish agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be

deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors

in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Snohomish pursuant to paragraph 9(a)(1), Bonneville shall bill Snohomish on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Snohomish shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate

Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such

terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Snohomish pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Snohomish on the monthly power bill, and Snohomish shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs,

and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Snohomish the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to

section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Snohomish written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Snohomish an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to

Snohomish on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Snohomish shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Snohomish an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to Snohomish on the monthly power bill the difference between such

actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Snohomish shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Snohomish pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Snohomish or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Snohomish on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Snohomish shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Snohomish the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Snohomish an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast

Reinforcement Cost, Bonneville shall bill Snohomish such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Snohomish shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Snohomish an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Snohomish such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Snohomish shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Snohomish pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Snohomish for wheeling provided pursuant to section 3(b)(1)(C)(i) on Snohomish's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Snohomish shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Snohomish shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Snohomish's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Snohomish pursuant to section 4 without incurring any liability to Snohomish therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Snohomish of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Snohomish makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Snohomish shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to

participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Snohomish shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Snohomish pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Snohomish pursuant to this Agreement; provided, however that Snohomish's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Snohomish pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Snohomish pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Snohomish, in a lump sum, any refund due to Snohomish pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Snohomish pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Snohomish under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Snohomish by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the

order of Snohomish, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Snohomish from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Snohomish's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Snohomish pursuant to this Agreement, Snohomish shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Snohomish and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Snohomish's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Snohomish's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Snohomish's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Snohomish's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11 REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Snohomish in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Snohomish of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Snohomish for purposes of effectuating remedial actions pursuant to this section.

(b) Snohomish's Responsibilities

(1) Snohomish shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Snohomish's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan

referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm Snohomish's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Snohomish shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Snohomish's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Snohomish pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Snohomish on Snohomish's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Snohomish shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Snohomish's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Snohomish and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Snohomish pursuant to subsection 11(b).

12 CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Snohomish may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Snohomish fails to appoint a representative to the Committee, Snohomish waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Snohomish hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Assistant General Manager for Rates and Resources

Alternate: Manager of Power Supply

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if

appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Snohomish, change the

designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. **OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN**

(a) The provisions of this section shall become effective commencing August 1, 1995, provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Snohomish, and Snohomish shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the

fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year

to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Snohomish and Capacity Owners other than Snohomish and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the

representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested; 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or

forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such

written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d) Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's

rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any

actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project, provided, however, that, without limiting any of Snohomish's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Snohomish and Capacity Owners other than Snohomish regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l)

through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Snohomish's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Snohomish is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Snohomish shall act through the Committee. Each of Bonneville and Snohomish agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to

the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville

written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Snohomish, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to

the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Snohomish each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those

parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Snohomish shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Snohomish its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners.

The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Snohomish or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Snohomish pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such

project; provided, however, that, without limiting any of Snohomish's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the

Committee or Snohomish, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number

of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and

information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into

consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Snohomish and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. **AUDIT RIGHTS**

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Snohomish pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Snohomish pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Snohomish or any Capacity Owner other than Snohomish for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for

such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Snohomish a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Snohomish a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Snohomish as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Snohomish's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Snohomish.

(f) If an audit report provided to Bonneville by Snohomish pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Snohomish a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Snohomish a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Snohomish as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Snohomish's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Snohomish; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Snohomish shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Snohomish chooses not to participate in any audit undertaken by the Committee, then Snohomish shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and

Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Snohomish of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Snohomish is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Snohomish's books, records, and documents that directly pertain to the revenue reportable in Snohomish's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Snohomish shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Snohomish is required by regulatory authority to purchase

or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Snohomish has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Snohomish or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Snohomish at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Snohomish may, within 90

days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Snohomish may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Snohomish may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Snohomish's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Snohomish has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Snohomish's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Snohomish's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Snohomish' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Snohomish's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Snohomish of the amount of the Refunded Lump Sum Payment.

If Snohomish elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to Snohomish and Capacity Owners other than Snohomish, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Snohomish or any Capacity Owner other than Snohomish.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Snohomish may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Snohomish may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Snohomish may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Snohomish's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Snohomish has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Snohomish's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + R = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Snohomish of the amount of Refunded Lump Sum Payment.

If Snohomish elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Snohomish and Capacity Owners other than Snohomish, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Snohomish or any Capacity Owner other than Snohomish.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Snohomish, and Capacity Owners other than Snohomish shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Snohomish in substantially the same position with respect to Snohomish's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the

expiration of the AC-93 rate. Bonneville, Snohomish, and Capacity Owners other than Snohomish shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Snohomish, and Capacity Owners other than Snohomish reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Snohomish, and Capacity Owners other than Snohomish do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Snohomish and Capacity Owners other than Snohomish and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Snohomish, and Capacity Owners other than Snohomish are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Snohomish may elect, within 6 months of any of the foregoing events, to terminate this

Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Snohomish's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Snohomish elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Snohomish shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Snohomish's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Snohomish a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Snohomish's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Snohomish's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Snohomish pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Snohomish to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Snohomish to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each

monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Snohomish of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Snohomish's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Snohomish fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Snohomish shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period,

Bonneville and Snohomish shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Snohomish and Capacity Owners other than Snohomish. If Bonneville and Snohomish do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Snohomish, and Snohomish shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Snohomish's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and

section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Snohomish and Capacity Owners other than Snohomish.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and Snohomish agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be

applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. **NOTICES**

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) Amendments

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) Entire Agreement

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Snohomish shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Snohomish an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Snohomish during the development or consideration of any offer to any Capacity Owner other than

Snohomish to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate

set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Snohomish is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Snohomish's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Snohomish acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September 27, 1994

Date September 27, 1994

Public Utility District No. 1 of Snohomish County

By John F Spencer

/s/ JOHN F. SPENCER

Name John Spencer
(Print/Type)

Title General Manager

General Manager

Date 9/23/94

September 23, 1994

Effective Date September 27, 1994

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rate transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridi

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment, if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$XXX)} * \%}{725\ \text{MW} * \#\ \text{months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	42 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

Facilities whose costs will be adjusted using change Between Estimate and Actual		($ in Thousands) (1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Snohomish's Capacity Ownership Share	=	42 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$9,030,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Snohomish. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Snohomish's Capacity Ownership Share	=		42 MW
2.	Adjusted Capacity Ownership Price	X	$	
3.	Adjusted Lump Sum Payment[1]	=		
4.	Initial Lump Sum Payment	–		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Snohomish	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Snohomish	=		

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Snohomish receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Snohomish's Capacity Ownership Share	=		42 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Snohomish	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Snohomish	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Snohomish receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Snohomish receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Snohomish receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Snohomish's schedules for transactions transmitted on Snohomish's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Snohomish's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		
6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.		
For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Snohomish, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Snohomish and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Snohomish and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Snohomish or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Snohomish or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Snohomish and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Snohomish has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Snohomish shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Snohomish shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Snohomish agrees as follows:

(1) Snohomish shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Snohomish shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Snohomish shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Snohomish shall, in all solicitations or advertisements for employees placed by or on behalf of Snohomish, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Snohomish shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Snohomish's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Snohomish shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Snohomish shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Snohomish shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Snohomish's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Snohomish is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Snohomish may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Snohomish as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Snohomish shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Snohomish shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Snohomish becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Snohomish may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Snohomish certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Snohomish agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Snohomish agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Snohomish to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Snohomish hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Snohomish further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Snohomish's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Snohomish shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Snohomish acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Snohomish agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Snohomish agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Snohomish and Bonneville shall, in concert with the Capacity Owners other than Snohomish, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Snohomish pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Snohomish shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2			
C. AFUDC				
AFUDC of Replacements and Reinforcements	3			
D. Interest				
Interest Cost of Replacements and Reinforcements	4			
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5			

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1			
B. Other PNW AC Intertie costs	2			
C. Total Other Costs	3			

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1			
Total contracts and rates cost from rate case	2			
Contracts and rates cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5			
Contracts and rates indirect costs	6			
Contracts and rates overhead costs	7			
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8			
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9			

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1			
Total power scheduling cost from rate case	2			
Power scheduling cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Power Scheduling Costs				
Power scheduling direct costs	5			
Power scheduling indirect costs	6			
Power scheduling overhead costs	7			
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8			
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9			

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2			
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	( )	( )	( )
D. End of Term Costs	4			

Snohomish's Initial Transaction with California Utility

Name of parties: Snohomish / Sacramento Municipal Utility District

Term of Contract: September 30, 2007

Date of Execution: May 26, 1993

Amount of Transaction (MW): 42 MW

Amendment No. 3
Contract No. DE-MS79-94BP-94523

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

POWER RESOURCES COOPERATIVE

(Formerly PACIFIC NORTHWEST GENERATING COOPERATIVE)

This AMENDMENT to the PNW AC Intertie Capacity Ownership Agreement, Contract Number 94PB-94523, (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and Power Resources Cooperative, formerly known as Pacific Northwest Generating Cooperative (Customer). The Customer and BPA are sometimes referred to individually as "Party", and collectively as "Parties" as the context suggests below.

This Amendment No. 3 (Amendment) to the Agreement between BPA and the Customer acknowledges that on March 7, 1996, amended articles of incorporation were filed by Customer with the Secretary of State of Oregon formally changing its name to Power Resources Cooperative (PRC).

BPA and the Customer agree:

1. **EFFECTIVE DATE**
This Amendment shall take effect on the date executed by the Parties (Effective Date).

2. **AMENDMENT OF AGREEMENT**
BPA and the Transmission Customer wish to amend the Agreement as follows:

   (a) All references in the Agreement to "Pacific Northwest Generating Cooperative" or "PNGC" are hereby replaced with "Power Resources Cooperative."

3. **OTHER TERMS AND CONDITIONS UNAFFECTED**
The Parties agree that all other terms and conditions of the Agreement are unaffected by this Amendment.

4. **SIGNATURES**

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

POWER RESOURCES COOPERATIVE

By Joseph W. Nadal, Jr.

Name Joseph W. Nadal, Jr.
(Print/Type)

Title Senior Vice President

Date 11/30/2000

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Thomas M. Noguchi
Sr. Transmission Account Executive

Name Thomas M. Noguchi
(Print/Type)

Date 11/29/2000

12-04-00P02:33 RCVD

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Amendatory Agreement No. 2 to
Contract No. DE-MS79-94BP94523

AMENDATORY AGREEMENT
to the
PACIFIC NORTHWEST AC INTERTIE
CAPACITY OWNERSHIP AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFIC NORTHWEST GENERATING COOPERATIVE

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This AMENDATORY AGREEMENT is executed as of February 5, 1997 by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (hereinafter referred to as "BPA") and the PACIFIC NORTHWEST GENERATING COOPERATIVE (hereinafter referred to as "PNGC"), an Oregon cooperative corporation. The PNGC and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

W I T N E S S E T H :

WHEREAS the Parties on September 27, 1994, entered into the Pacific Northwest AC Intertie Capacity Ownership Agreement, Contract No. DE-MS79-94BP94523 (Agreement); and

WHEREAS the Parties on September 30, 1994, entered into Amendatory Agreement No. 1 to the Agreement which revised subsection 3(b)(2); and

WHEREAS the Federal Energy Regulatory Commission (FERC) has issued Order No. 888, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities and Transmitting Utilities;" and

WHEREAS the Parties desire to amend the Agreement so as to comply with such Order No. 888 and 889.

NOW, THEREFORE, the Parties agree as follows:

1. **DEFINITIONS**

Capitalized terms used in this Amendatory Agreement, unless otherwise defined herein, have the respective meanings set forth for such terms in the Agreement.

2. **AMENDMENT OF AGREEMENT**

Subsection 3(b) of the Agreement is deleted in its entirety and the following is inserted in lieu thereof:

(b) **Right to Wheel for Third Parties**

The PNGC may use its Scheduling Share to transmit any and all power and energy whether or not such power or energy is owned by PNGC. The PNGC shall have no obligation under this Agreement to make available to BPA any portion of PNGC's Scheduling Share which is unused in any hour, and BPA shall not schedule over PNGC's Scheduling Share without PNGC's prior written consent.

BPA shall treat all scheduling information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of FERC's regulations.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendatory Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Thomas M. Noguchi
Senior Account Executive

Name Thomas M. Noguchi
(Print/Type)

Date 2/3/97

PACIFIC NORTHWEST GENERATING COOPERATIVE

By David E. Piper

Name David E. Piper
(Print/Type)

Title President and CEO

Date 2/5/97

(HQ5F01-TMC-W:\MCP\TMC\CT\94523.DOC)

PNGC

Pacific Northwest Generating Cooperative

"Partners in Power Management"

February 7, 1997

Tom Noguchi
Customer Account Executive
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Dear Tom,

Here is a copy of the executed Capacity Ownership Agreement, Contract No. DE-MS79-94BP94523. Thank you for your help.

Sincerely,

Aleka U. Kitchen
Senior Power Management Specialist

Enclosure

711 NE Halsey, Suite 200 • Portland, OR 97232-1268 • (503) 288-1234 • Fax: (503) 288-2334

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

In reply refer to: PMT

SEP 26 1994

Amendatory Agreement No. 1
Contract No. DE-MS79-94BP94523

Mr. Joseph W. Nadal
Director of Power Management
Pacific Northwest Generating Cooperative
711 NE. Halsey, Suite 200
Portland, OR 97232

Dear Mr. Nadal:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and the Pacific Northwest Generating Cooperative (PNGC), an Oregon cooperative corporation, to amend Contract No. DE–MS79–94BP94523 (Capacity Ownership Agreement), executed by PNGC on September 23, 1994, and responds to PNGC's August 24, 1994, letter regarding the Capacity Ownership Agreement. This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and PNGC agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) PNGC may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PNGC. PNGC agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to PNGC under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) PNGC hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. PNGC does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of

Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to PNGC consistent with the above.

PNGC and Bonneville agree to negotiate in good faith the terms and conditions under which PNGC shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PNGC or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only PNGC)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to PNGC shall mean PNGC or its designee. Any such designee shall be identified in writing by PNGC to Bonneville. Only one entity may submit schedules on PNGC's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to PNGC, please sign and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Walter E. Pollock
Group Vice President, Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

PACIFIC NORTHWEST GENERATING COOPERATIVE

By _____

Name David E. Piper
(Print/Type)

Title Executive V.P. & General Manager

Date 9/30/94

Effective Date _____

(PMLAN-W:\PMT\CONTRACT\LTR_AGMT\94523AM1.DOC)

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94523

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC NORTHWEST GENERATING COOPERATIVE

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (PNGC's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the PACIFIC NORTHWEST GENERATING COOPERATIVE (PNGC), an Oregon cooperative corporation. Each of Bonneville and PNGC is sometimes referred to individually in this Agreement as "Party"; Bonneville and PNGC are sometimes referred to together in this Agreement as "Parties."

W I T N E S S E T H :

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and PNGC executed a Memorandum of Understanding, DE-MS79-92BP93488, dated October 11, 1991, which, among other things, sets forth the principles for PNGC's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and PNGC are executing Contract No. DE-MS79-94BP94151 to provide PNGC with, among other things, network wheeling between the John Day Substation and PNGC's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and PNGC agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by PNGC's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than PNGC) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than PNGC) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PNGC pursuant to this Agreement, which percentage is determined by dividing PNGC's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of PNGC pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PNGC pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by PNGC's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with

the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by PNGC to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by PNGC.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PNGC for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PNGC for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by PNGC's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by PNGC pursuant to this Agreement, which percentage is determined by dividing PNGC's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of PNGC's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or PNGC.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the later of (1) the date of execution and delivery of this Agreement by both of the Parties, and (2) the date by which this Agreement has, with respect to PNGC, been approved by the Rural Electrification Administration (REA). To the extent required to do so by REA, PNGC shall submit this Agreement to REA for approval no later than three Working Days after the date on which this Agreement is executed by both Parties. Bonneville shall provide PNGC with a copy of the executed Agreement on the next Working Day after Bonneville executes the Agreement. PNGC shall use best efforts to obtain from REA on the earliest possible date REA's permission that this Agreement become effective in accordance with subsection 2(a). This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by PNGC until payment is made by PNGC pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from PNGC pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate

this Agreement by delivering to PNGC written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to PNGC pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to PNGC, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, PNGC purchases from Bonneville and Bonneville sells to PNGC the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, PNGC shall notify Bonneville in writing of PNGC's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and PNGC shall have the right to utilize its Scheduling Share pursuant to the paragraph PNGC elects. Prior to Bonneville's receipt of such notification, PNGC shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If PNGC fails to make an election within the

prescribed time period, PNGC shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), PNGC shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that PNGC does not own at the California-Oregon border or for which transmission PNGC receives any revenue that would be reportable in PNGC's accounting system where revenues received for wheeling for other entities would be booked.

(B) If PNGC's Scheduling Share is not fully utilized by PNGC in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of PNGC's Scheduling Share for such hour but no longer than such hour. PNGC shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), PNGC's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that PNGC has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of PNGC's Scheduling Share. In return for PNGC's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay PNGC

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-

south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of PNGC's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of PNGC's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When PNGC's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie

Operational Transfer Capability such that PNGC's Scheduling Share for such hour is less than the MW amount of the aggregate of PNGC's net firm transactions identified by PNGC to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of PNGC's firm transactions that equals the difference between PNGC's Scheduling Share for such hour and the MW amount of the aggregate of PNGC's firm transactions for such hour up to, but not in excess of, PNGC's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom PNGC is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. PNGC shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to PNGC pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for

Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to PNGC pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PNGC or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, PNGC shall identify such firm transaction to Bonneville. PNGC shall identify such firm transaction to Bonneville by providing to Bonneville a copy of PNGC's contract for such firm transaction (after information considered proprietary by PNGC has been redacted by PNGC). Bonneville shall review such contract to verify that the transaction is firm. If PNGC and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) PNGC retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) PNGC may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PNGC. PNGC shall have no obligation under this Agreement to make available to Bonneville any portion of PNGC's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over PNGC's Scheduling Share without PNGC's prior consent.

(B) PNGC hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide PNGC with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) PNGC shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when PNGC uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) PNGC (and only PNGC) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to PNGC's Scheduling Share for such hour. The MW amount of PNGC's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of PNGC's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) PNGC shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to PNGC on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify PNGC of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor

(Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify PNGC no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify PNGC no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) PNGC shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, PNGC shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) PNGC shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make PNGC's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that PNGC's schedule exceeds PNGC's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to PNGC information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify PNGC in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) PNGC's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) PNGC's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. PNGC may elect to acquire a share of such Upgrade in an amount up to PNGC's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, PNGC shall notify Bonneville in writing of PNGC's decision regarding such acquisition. If PNGC elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, PNGC's notice to Bonneville shall include the percentage of such Upgrade that PNGC elects to acquire (Acquisition Percentage). If PNGC fails to notify Bonneville within such 100-day period, PNGC shall be deemed to have elected not to acquire any of such Upgrade.

(d) If PNGC elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to PNGC shall be PNGC's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. PNGC shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If PNGC's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to PNGC and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If PNGC and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), PNGC may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to PNGC such portion of the Unacquired Share as has been apportioned to PNGC pursuant to the Apportionment, and Bonneville shall offer to PNGC such portion of the Unacquired Share.

(2) If Bonneville does not receive from PNGC and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to PNGC and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = PNGC's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following PNGC's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), PNGC shall notify Bonneville in writing of PNGC's decision regarding acquisition of the Additional Share Offered. If PNGC fails to notify Bonneville within such 30-day period, PNGC shall be deemed to have elected not to acquire any of the Additional Share Offered. If PNGC elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) PNGC shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as PNGC elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to PNGC with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by PNGC pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. PNGC shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After PNGC has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), PNGC's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from PNGC's elections pursuant to subsections 5(c) and (e). Revision

of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by PNGC to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by PNGC in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by PNGC to any other Capacity Owner of all or part of its Capacity Ownership Share and all of PNGC's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by PNGC of the entire Agreement and of all of PNGC's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by PNGC of this Agreement or of any of PNGC's rights under this Agreement as security for any indebtedness, whether present or future, of PNGC pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between PNGC and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if PNGC has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, PNGC shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If PNGC transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, PNGC shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance

outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to PNGC's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify PNGC in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify PNGC in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. PNGC's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and PNGC based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and PNGC have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to PNGC pursuant to this subsection 7(d) shall not be payable by PNGC pursuant to this Agreement.

(e) Bonneville shall provide PNGC notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on PNGC's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to PNGC's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain PNGC's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately

preceding clause (ii) that would have a substantial negative impact on PNGC's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without PNGC's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, PNGC hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, PNGC shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to PNGC in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to PNGC for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. PNGC shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and PNGC agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to PNGC, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, PNGC shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to PNGC, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of

Bonneville and PNGC agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by PNGC pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to PNGC pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to PNGC a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then PNGC shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to PNGC, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to

the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and PNGC agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from PNGC pursuant to paragraph 9(a)(1), Bonneville shall bill PNGC on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. PNGC shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing PNGC pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill PNGC on the monthly power bill, and PNGC shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being

hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to PNGC the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide PNGC written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to PNGC an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in

Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to PNGC on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PNGC shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to PNGC an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B,

D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to PNGC on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PNGC shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill PNGC pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to PNGC or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill PNGC on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. PNGC shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill PNGC the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to PNGC an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PNGC such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PNGC shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to PNGC an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PNGC such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PNGC shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill PNGC pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term

"AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill PNGC for wheeling provided pursuant to section 3(b)(1)(C)(i) on PNGC's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and PNGC shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, PNGC shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to PNGC's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to PNGC pursuant to section 4 without incurring any liability to PNGC therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by PNGC of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which PNGC makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, PNGC shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), PNGC shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by PNGC pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by PNGC pursuant to this Agreement; provided, however that PNGC's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect

to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to PNGC pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to PNGC pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to PNGC, in a lump sum, any refund due to PNGC pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to PNGC pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to PNGC under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to PNGC by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of PNGC, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by PNGC from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on PNGC's power bill.

10. **TRANSMISSION LOSSES**

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by PNGC pursuant to this Agreement, PNGC shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of PNGC and

Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to PNGC's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. PNGC's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of PNGC's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) PNGC's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify PNGC in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written

notice to PNGC of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to PNGC for purposes of effectuating remedial actions pursuant to this section.

(b) **PNGC's Responsibilities**

(1) PNGC shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain PNGC's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm PNGC's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, PNGC shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain PNGC's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by PNGC pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be

determined by dividing the amount of power scheduled by PNGC on PNGC's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) PNGC shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to PNGC's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) PNGC and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of PNGC pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

PNGC may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period PNGC fails to appoint a representative to the Committee, PNGC waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. PNGC hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Director of Power Management

Alternate:

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than PNGC, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to PNGC, and PNGC shall not have any obligation

pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection

13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among PNGC and Capacity Owners other than PNGC and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss

factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for

documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of PNGC's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into

good faith negotiations with PNGC and Capacity Owners other than PNGC regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of PNGC's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which PNGC is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, PNGC shall act through the Committee. Each of Bonneville and PNGC agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that

has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and PNGC, respectively.

The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and PNGC each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no

authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then PNGC shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill PNGC its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the PNGC or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of PNGC pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of PNGC's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6

and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by

either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity

Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or PNGC, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating

Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief

Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the

Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of

Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon PNGC and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to PNGC pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to PNGC pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge PNGC or any Capacity Owner other than PNGC for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PNGC a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to PNGC a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to PNGC as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PNGC's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to PNGC.

(f) If an audit report provided to Bonneville by PNGC pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PNGC a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to PNGC a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to PNGC as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PNGC's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to PNGC; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if

Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) PNGC shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If PNGC chooses not to participate in any audit undertaken by the Committee, then PNGC shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal

course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by PNGC of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If PNGC is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review PNGC's books, records, and documents that directly pertain to the revenue reportable in PNGC's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

PNGC shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless PNGC is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether PNGC has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to PNGC or by a seller of power or energy, which power or energy is not resource-specific and is delivered to PNGC at a point that connects one or more resources or transmission systems.

18. **ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION**

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, PNGC may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PNGC may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PNGC may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by

PNGC to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PNGC's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PNGC has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PNGC's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment,

Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of PNGC's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives PNGC' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives PNGC's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to PNGC of the amount of the Refunded Lump Sum Payment.

If PNGC elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to PNGC and Capacity Owners other than PNGC, or to any of them, the cost to Bonneville of the

Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PNGC or any Capacity Owner other than PNGC.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), PNGC may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PNGC may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PNGC may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PNGC's notification to terminate this Agreement pursuant to this subsection 18(c) except

for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PNGC has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PNGC's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + R = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the

first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to PNGC of the amount of Refunded Lump Sum Payment.

If PNGC elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to PNGC and Capacity Owners other than PNGC, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because

it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PNGC or any Capacity Owner other than PNGC.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, PNGC, and Capacity Owners other than PNGC shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place PNGC in substantially the same position with respect to PNGC's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, PNGC, and Capacity Owners other than PNGC shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, PNGC, and Capacity Owners other than PNGC reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, PNGC, and Capacity Owners other than PNGC do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of PNGC and Capacity Owners other than PNGC and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, PNGC, and Capacity Owners other than PNGC are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, PNGC may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to PNGC's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should PNGC elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) PNGC shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an

amount of power on the PNW-PSW Intertie up to PNGC's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to PNGC a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in PNGC's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of PNGC's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to PNGC pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by PNGC to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PNGC to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to PNGC of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) PNGC's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If PNGC fails to terminate the Agreement pursuant to subsection 18(e) as prescribed

therein as a result of FERC action, PNGC shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and PNGC shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, PNGC and Capacity Owners other than PNGC. If Bonneville and PNGC do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill PNGC, and PNGC shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time,

the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in PNGC's

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by PNGC and Capacity Owners other than PNGC.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and PNGC agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. **WAIVER**

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. **MISCELLANEOUS**

(a) **Effect of Section Headings**

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. PNGC shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or

any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to PNGC an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, PNGC during the development or consideration of any offer to any Capacity Owner other than PNGC to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that PNGC is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the PNGC's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by PNGC acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September 27, 1994

Date September 27, 1994

Pacific Northwest Generating Cooperative

By David E. Piper

Name DAVID E. PIPER
(Print/Type)

Title EXEC. VICE PRESIDENT

Date 9/26/94

/s/ DAVID E. PIPER

Executive Vice President

September 26, 1994

Effective Date _____

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$(XX))} * \%}{725\ \text{MW} * \#\ \text{months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	50 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual		(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	PNGC's Capacity Ownership Share	=	50 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$10,750,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to PNGC. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 7, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	PNGC's Capacity Ownership Share	=		50 MW
2.	Adjusted Capacity Ownership Price	X	$	
3.	Adjusted Lump Sum Payment[1]	=		
4.	Initial Lump Sum Payment	–		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to PNGC	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to PNGC	=		

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or PNGC receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	PNGC's Capacity Ownership Share	=		50 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to PNGC	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to PNGC	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or PNGC receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or PNGC receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or PNGC receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to PNGC's schedules for transactions transmitted on PNGC's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to PNGC's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	180 MVAR Reactor Bank No. 1	100	100
	• Breaker D#4222	100	100
	• Isolating Switch D#4060	100	100
	• Associated Arresters	100	100
	300 MVAR Reactor Bank No. 2	100	100
	• Breaker D#4720	100	100
	• Isolating Switch D#4719	100	100
	• Associated Arresters	100	100
	• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
	• Breaker D#4038	100	100
	• Isolating Switch D#4062	100	100
	• Neutral isolating switch D#4109/4081	100	100
	• Associated Arresters	100	100
	• Associated PTs	100	100
	• North Main Bus 500 kV PTs	100	100
	• South Main Bus 500 kV PTs	100	100
	Station General		
9.	**Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
	Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
10.	**Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
11.	**Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

PNGC, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation; liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, PNGC and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, PNGC and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by PNGC or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of PNGC or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, PNGC and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If , during any 12-month period (including the 12 months preceding the award of this contract), PNGC has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, PNGC shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, PNGC shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, PNGC agrees as follows:

(1) PNGC shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) PNGC shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) PNGC shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) PNGC shall, in all solicitations or advertisements for employees placed by or on behalf of PNGC, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) PNGC shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of PNGC's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) PNGC shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) PNGC shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) PNGC shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain PNGC's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that PNGC is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and PNGC may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against PNGC as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) PNGC shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) PNGC shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if PNGC becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, PNGC may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) PNGC certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. PNGC agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) PNGC agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by PNGC to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) PNGC hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. PNGC further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of PNGC's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

PNGC shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) PNGC acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) PNGC agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) PNGC agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event PNGC and Bonneville shall, in concert with the Capacity Owners other than PNGC, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by PNGC pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that PNGC shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1			
B. Other PNW AC Intertie costs	2			
C. Total Other Costs	3			

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1			
Total contracts and rates cost from rate case	2			
Contracts and rates cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5			
Contracts and rates indirect costs	6			
Contracts and rates overhead costs	7			
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8			
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9			

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		_____	
Total power scheduling cost from rate case	2		_____	
Power scheduling cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Power Scheduling Costs				
Power scheduling direct costs	5	_____	_____	_____
Power scheduling indirect costs	6	_____	_____	_____
Power scheduling overhead costs	7	_____	_____	_____
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2			
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	( )	( )	( )
D. End of Term Costs	4			

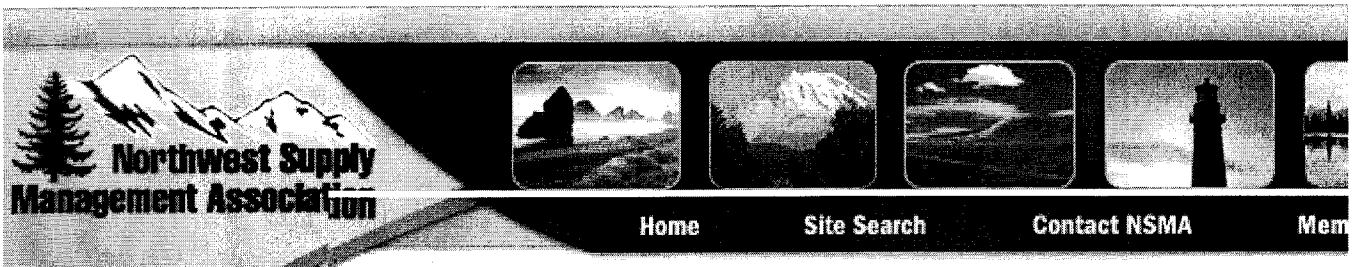
PNGC's Initial Transaction with California Utility

Name of parties: PNGC / Turlock Irrigation District

Term of Contract: December 31, 2018

Date of Execution: November 10, 1992

Amount of Transaction (MW): 52 MW



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Terms of Use

BONNEVILLE
POWER ADMINISTRATION

Transmission Business Line (TBL)

Draft Business Practice LOS-001.3

Real Power Loss Return Methodology, Version 3

Effective: March 1, 2004
Posted: February 24, 2004

Revised as follows:

- *Changed the frequency that customers are permitted to change Real Power Loss Providers from twice a year to four times a year in response to customer input.*
- *Other minor revisions for clarity and consistency.*

This document defines the process and guidelines by which transmission customers must return Real Power Losses to the Bonneville Power Administration (BPA) Power Business Line (PBL). The BPA Transmission Business Line (TBL) will refuse all schedule requests for Transmission Customers that have not made a declaration of their Real Power Loss Provider.

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A. Customers That Are Not Required to Return Real Power Losses 1

B. Real Power Loss Methodology for Point-to-Point (PTP) Customers 1

C. Real Power Loss Returns for non-Point-to-Point Customers 3

Revision History 3

A. Customers That Are Not Required to Return Real Power Losses

All Transmission Customers must return Real Power Losses, with the following exceptions:

- **BPA PBL Full Requirements Customers** do not need to return losses for energy delivered under a subscription contract that includes losses.
- **BPA PBL Partial Requirements Customers** do not need to return losses for energy delivered under BPA PBL Partial Requirements subscription agreements. *However*, Partial Requirements Customers must return Real Power Losses for the non-Federal portion of their power deliveries, and must notify TBL of their Real Power Loss provider for the non-Federal portion of their power deliveries.
- BPA PBL **Block** power customers are not required to return losses for energy delivered under a BPA PBL Block power contract.

B. Real Power Loss Methodology for Point-to-Point (PTP) Customers

1. Real Power Loss returns can be from a Control Area, a system, or a remote generator resource within the network segment. If a remote resource is down for any reason, the Transmission Customer must deliver energy to the remote

resource to ensure that the loss schedule is returned. This provides comparable loss return schedules for all providers of loss schedules from one loss provider. All losses must be provided from one Control Area, one system, or one remote generator.

2. The Transmission Customer is responsible for delivering its required Real Power Losses to TBL. A customer may elect to be its own Real Power Loss Provider, or may designate one alternate Real Power Loss Provider to deliver the Transmission Customer's Real Power Losses to TBL. TBL will not charge Transmission Customers for transmission to return Real Power Losses. A Transmission Customer's alternate Real Power Loss Provider may use its own transmission or the Transmission Customer's "no charge" transmission reservation, as described in section 3, to return the Transmission Customer's losses to TBL on behalf of the Transmission Customer.

   Transmission Customers must notify their TBL Account Executive in writing of their designated Real Power Loss Provider using the form provided by the designated account executive. Transmission Customers may change their Real Power Loss provider with 60 days' prior written notice to their TBL Account Executive. Transmission Customers may not change their Real Power Loss Provider more than four times in any fiscal year (i.e., customers are allowed no more than 4 RPL Providers in a fiscal year). Changes of Real Power Loss Providers may occur only at the beginning of a month.

3. Transmission charges associated with the return of Real Power Losses are already included in the charges associated with the transmission service that generated the losses, so TBL does not assess additional transmission charges for the return of Real Power Losses. However, to allow TBL to determine and track Available Transmission Capacity (ATC), Transmission Customers or their alternate Real Power Loss Provider must return Real Power Losses to PBL on firm transmission using either "no charge reservations for losses" or previously reserved transmission.

   A reservation product code for "no charge reservation for losses" is posted on the NW Open Access Same Time Information System (OASIS). The transmission loss reservation must show the Point Of Receipt (POR) as the Real Power Loss provider and the Point Of Delivery (POD) will be BPA Power.

   For TBL posted external constrained paths, Transmission Customers or their alternate Real Power Loss Providers for transmission may use previously reserved transmission at a POR or may request a new "no charge reservation for losses". "No charge reservation for losses" can be used only for transmission of loss schedules.

   Real Power Loss return schedules are firm and subject to pro rata curtailment in real time. Real Power Loss returns that are curtailed must be returned as soon as possible and no later than 168 hours from the time of the curtailment.

4. TBL will continue to calculate Real Power Losses for its transmission system, and will send a daily report to all Transmission Customers with their loss schedules. Those schedules may also be viewed on the Customer Web Interface (CWI). Please contact TBL Scheduling for more information on how to get access to CWI.

5. The Unauthorized Increase Charge (UIC), Section II. G. of TBL's 2004 Transmission and Ancillary Service Rate Schedules, will apply if the Transmission Customer, using its own Reserved Capacity to return Real Power Losses in lieu of a "no charge reservation for losses," schedules transmission in excess of its Reserved Capacity.

C. Real Power Loss Returns for non-Point-to-Point Customers

Non-PTP Transmission Customers will be charged as follows:

- Network Integration (NT) Transmission Customers will not be charged transmission for loss schedules. A Real Power Loss provider must be identified and losses returned, except as provided in Section A.
- Slice Customers do not require a "no charge reservation" when Slice is being used to provide the return of the Slice Customer's Real Power Losses. These losses are calculated in the same way as losses for other customers. However, instead of a return schedule the losses are deducted from the customer's share of Slice 168 hours later, prior to the share being made available for scheduling.
- Formula Power Transmission (FPT) Customer losses are as described in the Customer's FPT Contracts.
- Integration of Resources (IR) Customer losses are as described in the Customer's IR Contract.

If you have questions or comments regarding this posting, please contact Shirley Buckmier at smbuckmier@bpa.gov or your TBL Customer Account Executive.

Revision History

Version/Date	Summary
06/26/2003	• Section C revised to clarify how Real Power Losses are handled for Slice customers. • Added section A. to clarify which customers are not required to return real power losses. This was previously posted in a linked document and the link does not work consistently. • Removed nonworking link. • Renumbered/reformatted sections to conform to conventions. • Removed all references to submitting notification on OASIS, this capability does not exist. • Removed requirement for yearly notification, this is no longer required. • Minor edits for clarity and correction of typographical errors. • Moved statement about refusal of schedule requests to the top of the document. • Revised language for clarity.
11/26/2001	Multiple marked updates.
09/20/2001	Minor revisions.

09/07/2001	Minor revisions.
09/06/2001	Added a link to a supplementary document
08/08/2001	Original business practice to define method for returning real power losses.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

JAN 11 1995

Amendatory Agreement No. 2
Contract No. DE-MS79-95BP94628

Mr. Jerry Miller, Manager
Power System Services
PacifiCorp
825 NE. Multnomah Street, Suite 625
Portland, OR 97232

Dear Mr. Miller:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and PacifiCorp, a corporation organized and existing under the laws of the State of Oregon, to amend Contract No. DE-MS79-95BP94628 (Capacity Ownership Agreement).

Bonneville and PacifiCorp agree that the first sentence of section 2(a) shall be stricken and replaced with the following sentence:

> "This Agreement shall become effective January 1, 1995, unless otherwise determined by FERC."

Should the Federal Energy Regulation Committee determine the Effective Date of the Capacity Ownership Agreements to be after January 1, 1995, PacifiCorp agrees to pay Bonneville Southern Intertie firm wheeling charges for PacifiCorp's use of its Capacity Ownership Share between January 1, 1995, and the Effective Date as established by FERC.

If the foregoing terms are acceptable to PacifiCorp, please sign both copies and return one copy of this amendment. The remaining copy is for your files.

Sincerely,

Senior Account Executive

Name Patrick G. McRae
(Print/Type)

ACCEPTED:

PACIFICORP

By

Name Jerry D. Miller
(Print/Type)

Title Manager, Power System Services

Date January 23, 1995

(PMLAN-MPSM-W:\MPSM\CTL\TRAGT\94628.DOC)

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Amendatory Agreement No. 1
Contract No. DE-MS79-95BP94628

Mr. Jerry Miller, Director
Power System Services
PacifiCorp Electric Operations
825 NE. Multnomah Street, Suite 625
Portland, OR 97232

Dear Mr. Miller:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and PacifiCorp Electric Operations (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon, to amend Contract No. DE–MS79–95BP94628 (Capacity Ownership Agreement). This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and PacifiCorp agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) PacifiCorp may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PacifiCorp. PacifiCorp agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to PacifiCorp under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) PacifiCorp hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. PacifiCorp does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of

Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to PacifiCorp consistent with the above.

PacifiCorp and Bonneville agree to negotiate in good faith the terms and conditions under which PacifiCorp shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PacifiCorp or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only PacifiCorp)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to PacifiCorp shall mean PacifiCorp or its designee. Any such designee shall be identified in writing by PacifiCorp to Bonneville. Only one entity may submit schedules on PacifiCorp's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to PacifiCorp, please sign both copies and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Senior Account Executive

Name Patrick G. McRae
(Print/Type)

ACCEPTED:

PACIFICORP/ELECTRIC OPERATIONS

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date December 27, 1994

(PMLAN-MPSM-W:\MPSM\CT\LTRAGT\94628AA1.DOC)

Contract No. DE-MS79-95BP94628

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

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This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of December 28, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the PACIFICORP (PacifiCorp), a corporation operating and existing under the laws of the state of Oregon. Each of Bonneville and PacifiCorp is sometimes referred to individually in this Agreement as "Party"; Bonneville and PacifiCorp are sometimes referred to together in this Agreement as "Parties."

W I T N E S S E T H :

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by PacifiCorp's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and PacifiCorp executed a Memorandum of Understanding, DE-MS79-91BP93469, dated September 18, 1991, which, among other things, sets forth the principles for PacifiCorp's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and PacifiCorp agree as follows:

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by Capacity Owners and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PacifiCorp pursuant to this Agreement, which percentage is determined by dividing PacifiCorp's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of PacifiCorp pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by PacifiCorp pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year

Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by PacifiCorp's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for

such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or

Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice)

resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Oregon, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by PacifiCorp to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each

Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by PacifiCorp.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PacifiCorp for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to PacifiCorp for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by PacifiCorp's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement, interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by PacifiCorp pursuant to this Agreement, which percentage is determined by dividing

PacifiCorp's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of PacifiCorp's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or PacifiCorp.

2. TERM AND TERMINATION

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by PacifiCorp until payment is made by PacifiCorp pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from PacifiCorp pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to PacifiCorp written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to PacifiCorp pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes

and delivers this Agreement to PacifiCorp, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, PacifiCorp purchases from Bonneville and Bonneville sells to PacifiCorp the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, PacifiCorp shall notify Bonneville in writing of PacifiCorp's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and PacifiCorp shall have the right to utilize its Scheduling Share pursuant to the paragraph PacifiCorp elects. Prior to Bonneville's receipt of such notification, PacifiCorp shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If PacifiCorp fails to make an election within the prescribed time period, PacifiCorp shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) No Third Party Wheeling

(A) Except as expressly provided in subparagraph 3(b)(1)(B), PacifiCorp shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that PacifiCorp does not own at the California-Oregon border or for which transmission PacifiCorp receives any revenue that would be reportable in PacifiCorp's accounting system where revenues received for wheeling for other entities would be booked.

(B) If PacifiCorp's Scheduling Share is not fully utilized by PacifiCorp in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of PacifiCorp's Scheduling Share for such hour but no longer than such hour. PacifiCorp shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), PacifiCorp's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that PacifiCorp has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of PacifiCorp's Scheduling Share. In return for PacifiCorp's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay PacifiCorp

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of PacifiCorp's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of PacifiCorp's unused

Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When PacifiCorp's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that PacifiCorp's Scheduling Share for such hour is less than the MW amount of the aggregate of PacifiCorp's net firm transactions identified by PacifiCorp to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of PacifiCorp's firm transactions that equals the difference between PacifiCorp's Scheduling Share for such hour and the MW amount of the aggregate of PacifiCorp's firm transactions for such hour up to, but not in

excess of, PacifiCorp's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom PacifiCorp is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. PacifiCorp shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to PacifiCorp pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to PacifiCorp pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to PacifiCorp or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, PacifiCorp shall identify such firm transaction to

Bonneville. PacifiCorp shall identify such firm transaction to Bonneville by providing to Bonneville a copy of PacifiCorp's contract for such firm transaction (after information considered proprietary by PacifiCorp has been redacted by PacifiCorp). Bonneville shall review such contract to verify that the transaction is firm. If PacifiCorp and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) PacifiCorp retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) PacifiCorp may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by PacifiCorp. PacifiCorp shall have no obligation under this Agreement to make available to Bonneville any portion of PacifiCorp's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over PacifiCorp's Scheduling Share without PacifiCorp's prior consent.

(B) PacifiCorp hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term

Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide PacifiCorp with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) PacifiCorp shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when PacifiCorp uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) PacifiCorp (and only PacifiCorp) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to PacifiCorp's Scheduling Share for such hour. The MW amount of PacifiCorp's Scheduling Share deemed to be scheduled on the PNW AC Intertie

pursuant to this Agreement, in any hour, shall be determined as the net of PacifiCorp's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) PacifiCorp shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to PacifiCorp on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify PacifiCorp of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify PacifiCorp no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify PacifiCorp no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) PacifiCorp shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, PacifiCorp shall submit its

Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) PacifiCorp shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the

hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make PacifiCorp's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that PacifiCorp's schedule exceeds PacifiCorp's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to PacifiCorp information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify PacifiCorp in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) PacifiCorp's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) PacifiCorp's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such

Upgrade. PacifiCorp may elect to acquire a share of such Upgrade in an amount up to PacifiCorp's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, PacifiCorp shall notify Bonneville in writing of PacifiCorp's decision regarding such acquisition. If PacifiCorp elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, PacifiCorp's notice to Bonneville shall include the percentage of such Upgrade that PacifiCorp elects to acquire (Acquisition Percentage). If PacifiCorp fails to notify Bonneville within such 100-day period, PacifiCorp shall be deemed to have elected not to acquire any of such Upgrade.

(d) If PacifiCorp elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to PacifiCorp shall be PacifiCorp's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. PacifiCorp shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If PacifiCorp's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to PacifiCorp and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If PacifiCorp and each of such other Capacity Owners have agreed in writing to an apportionment

as among themselves of the Unacquired Share (Apportionment), PacifiCorp may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to PacifiCorp such portion of the Unacquired Share as has been apportioned to PacifiCorp pursuant to the Apportionment, and Bonneville shall offer to PacifiCorp such portion of the Unacquired Share.

(2) If Bonneville does not receive from PacifiCorp and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to PacifiCorp and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = PacifiCorp's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following PacifiCorp's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), PacifiCorp shall notify Bonneville in writing of PacifiCorp's decision regarding acquisition of the Additional Share Offered. If PacifiCorp fails to notify Bonneville within such 30-day period, PacifiCorp shall be deemed to have elected not to acquire any of the Additional Share Offered. If PacifiCorp elects pursuant to this paragraph

5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) PacifiCorp shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as PacifiCorp elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to PacifiCorp with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by PacifiCorp pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. PacifiCorp shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After PacifiCorp has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), PacifiCorp's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from PacifiCorp's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by PacifiCorp to any person without

Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by PacifiCorp in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by PacifiCorp to any other Capacity Owner of all or part of its Capacity Ownership Share and all of PacifiCorp's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by PacifiCorp of the entire Agreement and of all of PacifiCorp's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by PacifiCorp of this Agreement or of any of PacifiCorp's rights under this Agreement as security for any indebtedness, whether present or future, of PacifiCorp pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between PacifiCorp and any mortgagee,

trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if PacifiCorp has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, PacifiCorp shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If PacifiCorp transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, PacifiCorp shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to PacifiCorp's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville

shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify PacifiCorp in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify PacifiCorp in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. PacifiCorp's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and PacifiCorp based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately

succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and PacifiCorp have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to PacifiCorp pursuant to this subsection 7(d) shall not be payable by PacifiCorp pursuant to this Agreement.

(e) Bonneville shall provide PacifiCorp notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on PacifiCorp's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to PacifiCorp's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain PacifiCorp's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on PacifiCorp's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without PacifiCorp's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, PacifiCorp hereby consents to Bonneville's modification of the Northwest Intertie Agreements or

Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, PacifiCorp shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to PacifiCorp in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to PacifiCorp for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. PacifiCorp shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and PacifiCorp agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) Calculation and Billing of the Adjusted Capacity Ownership Price

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual

construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to PacifiCorp, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, PacifiCorp shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to PacifiCorp, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and PacifiCorp agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by PacifiCorp pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to PacifiCorp pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to PacifiCorp a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership

Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then PacifiCorp shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to PacifiCorp, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and PacifiCorp

agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from PacifiCorp pursuant to paragraph 9(a)(1), Bonneville shall bill PacifiCorp on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. PacifiCorp shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing PacifiCorp pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill PacifiCorp on the monthly power bill, and PacifiCorp shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual

Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to PacifiCorp the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide PacifiCorp written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to PacifiCorp an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and

forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to PacifiCorp on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PacifiCorp shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to PacifiCorp an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast

Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to PacifiCorp on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. PacifiCorp shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill PacifiCorp pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and

until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to PacifiCorp or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill PacifiCorp on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. PacifiCorp shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual

Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill PacifiCorp the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to PacifiCorp an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PacifiCorp such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PacifiCorp shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to PacifiCorp an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual

Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill PacifiCorp such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and PacifiCorp shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill PacifiCorp pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill PacifiCorp for wheeling provided pursuant to section 3(b)(1)(C)(i) on PacifiCorp's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and PacifiCorp shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, PacifiCorp shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to PacifiCorp's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or

9(d), Bonneville shall be entitled to suspend performance of its obligations to PacifiCorp pursuant to section 4 without incurring any liability to PacifiCorp therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by PacifiCorp of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which PacifiCorp makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, PacifiCorp shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), PacifiCorp shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by PacifiCorp pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by PacifiCorp pursuant to this Agreement; provided, however that PacifiCorp's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to PacifiCorp pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to PacifiCorp pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to PacifiCorp, in a lump sum, any refund due to PacifiCorp pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to PacifiCorp pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to PacifiCorp under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to PacifiCorp by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of PacifiCorp, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by PacifiCorp from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on PacifiCorp's power bill.

10. **TRANSMISSION LOSSES**

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by PacifiCorp pursuant to this Agreement, PacifiCorp shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of PacifiCorp and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to PacifiCorp's net PNW AC Intertie schedule multiplied

by the appropriate loss factor specified in Exhibit E. PacifiCorp's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of PacifiCorp's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) PacifiCorp's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify PacifiCorp in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to PacifiCorp of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having

available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to PacifiCorp for purposes of effectuating remedial actions pursuant to this section.

(b) **PacifiCorp's Responsibilities**

(1) PacifiCorp shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain PacifiCorp's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm PacifiCorp's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, PacifiCorp shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain PacifiCorp's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by PacifiCorp pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by PacifiCorp on PacifiCorp's Scheduling Share in

such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) PacifiCorp shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to PacifiCorp's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) PacifiCorp and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of PacifiCorp pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

PacifiCorp may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period PacifiCorp fails to appoint a representative to the Committee, PacifiCorp waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. PacifiCorp hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Senior Vice President, Wholesale Transactions and Transmission

Alternate: Manager, Power System Services

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

If to PacifiCorp:

Senior Vice President, Wholesale Transactions
and Transmission
PacifiCorp Electric Operations
825 NE. Multnomah Street, Suite 625
Portland, OR 97232
Telephone (503) 731-2157
Facsimile (503) 731-2136

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than PacifiCorp, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to PacifiCorp, and PacifiCorp shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a

planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among PacifiCorp and Capacity Owners other than PacifiCorp and Bonneville's *rationale for such apportionment;*

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the

costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) *such documentation, data, and information relating to* Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such

request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional

documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting

documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan

(either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of PacifiCorp's

rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 *total overhead power scheduling costs;*

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with PacifiCorp and Capacity Owners other than PacifiCorp regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan

is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of PacifiCorp's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which PacifiCorp is obligated to pay pursuant to the terms and conditions of this

Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, PacifiCorp shall act through the Committee. Each of Bonneville and PacifiCorp agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and PacifiCorp, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and PacifiCorp each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in

California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then PacifiCorp shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill PacifiCorp its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration

proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be

arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the PacifiCorp or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of PacifiCorp pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of PacifiCorp's rights and benefits pursuant to section 16(f), no

Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration

pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or PacifiCorp, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the

Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then

within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or

information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the

Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon PacifiCorp and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. **AUDIT RIGHTS**

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to PacifiCorp pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to PacifiCorp pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge PacifiCorp or any Capacity Owner other than PacifiCorp for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits

undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PacifiCorp a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to PacifiCorp a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to PacifiCorp as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PacifiCorp's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to PacifiCorp.

(f) If an audit report provided to Bonneville by PacifiCorp pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to PacifiCorp a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to PacifiCorp a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to PacifiCorp as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by PacifiCorp's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to PacifiCorp; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) PacifiCorp shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If PacifiCorp chooses not to participate in any audit undertaken by the Committee, then PacifiCorp shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and

Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by PacifiCorp of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If PacifiCorp is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review PacifiCorp's books, records, and documents that directly pertain to the revenue reportable in PacifiCorp's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

PacifiCorp shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless PacifiCorp is required by regulatory authority to purchase

or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether PacifiCorp has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to PacifiCorp or by a seller of power or energy, which power or energy is not resource-specific and is delivered to PacifiCorp at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, PacifiCorp may, within 90

days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PacifiCorp may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PacifiCorp may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PacifiCorp's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PacifiCorp has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PacifiCorp's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of PacifiCorp's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives PacifiCorp' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives PacifiCorp's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to PacifiCorp of the amount of the Refunded Lump Sum Payment.

If PacifiCorp elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to PacifiCorp and Capacity Owners other than PacifiCorp, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PacifiCorp or any Capacity Owner other than PacifiCorp.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), PacifiCorp may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) PacifiCorp may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) PacifiCorp may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives PacifiCorp's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after PacifiCorp has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of PacifiCorp's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to PacifiCorp of the amount of Refunded Lump Sum Payment.

If PacifiCorp elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to PacifiCorp and Capacity Owners other than PacifiCorp, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from PacifiCorp or any Capacity Owner other than PacifiCorp.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place PacifiCorp in substantially the same position with respect to PacifiCorp's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the

expiration of the AC-93 rate. Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of PacifiCorp and Capacity Owners other than PacifiCorp and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, PacifiCorp, and Capacity Owners other than PacifiCorp are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, PacifiCorp may elect, within 6 months of any of the foregoing events, to terminate this Agreement

and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to PacifiCorp's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should PacifiCorp elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) PacifiCorp shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to PacifiCorp's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to PacifiCorp a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in PacifiCorp's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of PacifiCorp's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to PacifiCorp pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by PacifiCorp to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by PacifiCorp to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each

monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to PacifiCorp of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) PacifiCorp's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If PacifiCorp fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, PacifiCorp shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period,

Bonneville and PacifiCorp shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, PacifiCorp and Capacity Owners other than PacifiCorp. If Bonneville and PacifiCorp do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill PacifiCorp, and PacifiCorp shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in PacifiCorp's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and

section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by PacifiCorp and Capacity Owners other than PacifiCorp.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and PacifiCorp agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be

applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. **NOTICES**

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

To PacifiCorp:

Senior Vice President, Wholesale Transactions
and Transmission
PacifiCorp Electric Operations
825 NE. Multnomah Street, Suite 625
Portland, OR 97232

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) Amendments

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) Entire Agreement

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. PacifiCorp shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to PacifiCorp an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, PacifiCorp during the development or consideration of any offer to any Capacity Owner other than

PacifiCorp to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate

set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that PacifiCorp is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the PacifiCorp's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by PacifiCorp acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any

right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Account Executive

Name Patrick G. McRae
(Print/Type)

Date December 28, 1994

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date December 27, 1994

Effective Date January 1, 1995

(PMLAN-MPB-W:\PMT\CT\94628.DOC)

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

(PMLAN-MPSD-W:\PMT\CT\94628EXA.DOC)

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in \$/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$(KK))} * \%}{\text{725 MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A. the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B. the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. *End of Term*

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	32 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

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Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual	(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1. Alvey (Marion-Alvey Caps)	$5,739		
2. Slatt (Loop in - Breaker)	3,044		
3. Grizzly (BPA Breakers)	11,044		
4. *Loop into Slatt*	656		
5. Malin-Meridian loop into Captain Jack	982		
6. Alvey Substation - BPA	8,168		
7. Dixonville - PacifiCorp	8,635		
8. Meridian - PacifiCorp	6,548		
9. Power System Control	3,575		
10. Alvey-Spencer - BPA	1,346		
11. Spencer-Dixonville - PacifiCorp	20,388		
12. Dixonville-Meridian - PacifiCorp	32,140		
SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent			
13. Captain Jack (BPA Breakers)	$14,335		
14. Captain Jack (Communication and Control)	5,100		
15. Captain Jack (Series Capacitors)	722		
16. Power System Control	5,596		
17. Captain Jack line to Oregon-Calif. border	5,724		
SUBTOTAL	$31,477		
50 PERCENT OF SUBTOTAL	15,739		
TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	PacifiCorp's Capacity Ownership Share	=	32 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$6,880,000
4.	Deduction: Negotiation Deposit with Interest		
5.	Due to Bonneville:	=	$6,880,000

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

D. ADJUSTED LUMP SUM PAYMENT

1.	PacifiCorp's Capacity Ownership Share	=	32 MW
2.	*Adjusted Capacity Ownership Price*	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	_____
5.	SUBTOTAL due to Bonneville, or Refund *Due to PacifiCorp*	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to PacifiCorp	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or PacifiCorp receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	PacifiCorp's Capacity Ownership Share	=		32 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	*Adjusted Lump Sum Payment/immediately* preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to PacifiCorp	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to PacifiCorp	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or PacifiCorp receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or PacifiCorp receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or PacifiCorp receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to PacifiCorp's schedules for transactions transmitted on PacifiCorp's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to PacifiCorp's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

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Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	McNary line terminal		
	• 500 kV MOD D#5023/7847	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
2.	**John Day 500 kV** (Dispatch one-line diagram No. 132281)		
	Grizzly No.2 line terminal		
	• Breaker D#4131	100	50
	• Breaker D#4134	100	100
	• MOD D#4132	100	50
	• MOD D#4133/7867	100	100
	• MOD D#4135	100	100
	• Associated Line PTs	100	100
	Grizzly No.1 line terminal		
	• Breaker D#4140	100	50
	• Breaker D#4143	100	100
	• MOD D#4141	100	50
	• MOD D#4142/7869	100	100
	• MOD D#4144	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Station General		
3.	**Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
	Slatt No. 1 line terminal		
	• Breaker D#4967	100	57
	• Isolating switch D#4966/7328	100	57
	• Isolating switch D#4968/7355	100	57
	• Ground switch D#7415	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Summer Lake No. 1 line terminal		
	• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (*PacifiCorp's one-line diagram* PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230.kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1
PacifiCorp	DE-MS79-95BP94628	32	0.9

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities
PacifiCorp: PacifiCorp Electric Operations

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Seattle, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Seattle and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Seattle and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Seattle or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Seattle or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Seattle and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Seattle has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Seattle shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Seattle shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Seattle agrees as follows:

(1) Seattle shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Seattle shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Seattle shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Seattle shall, in all solicitations or advertisements for employees placed by or on behalf of Seattle, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Seattle shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Seattle's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Seattle shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Seattle shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Seattle shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Seattle's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Seattle is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Seattle may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Seattle as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Seattle shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Seattle shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Seattle becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Seattle may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Seattle certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Seattle agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Seattle agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Seattle to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Seattle hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Seattle further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Seattle's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Seattle shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Seattle acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Seattle agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Seattle agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event PacifiCorp and Bonneville shall, in concert with the Capacity Owners other than PacifiCorp, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by PacifiCorp pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that PacifiCorp shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor [Line 1/Line 2]	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor [Line 4/Line 5]	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost [Line 3 * Line 6 * Line 7]	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost [Line 3 * Line 6 * Line 9]	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost [Line 3 * Line 6 * Line 11]	12	_____	_____	_____
F. Operations Cost [Lines 8 + 10 + 12]	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor [Line 1/Line 2]	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor [Schedule A, line 3]	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie [Line 4 * Line 3 * Line 5]	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost [Line 6 + Line 7]	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance *indirect cost*	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs [Lines 1 + 2 + 3 + 4]	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission [Line 1 + Line 2 - Line 3 - Line 4 - Line 5]	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie [Line 7/Line 8]	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost [Line 9 * Line 10]	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor [Line 1/Line 2]	3		_____	
B. Allocation Factor				
MFU allocation factor [Schedule A, line 3]	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs [Line 5 + Line 6 + Line 7]	8	_____	_____	_____
D. Contracts and Rates Cost [Line 8 * Line 3 * Line 4]	9	_____	_____	_____

hedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		_____	
Total power scheduling cost from rate case	2		_____	
Power scheduling cost functionalization factor [Line 1/Line 2]	3		_____	
B. Allocation Factor				
MFU allocation factor [Schedule A, line 3]	4		_____	
C. Total Power Scheduling Costs				

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1			
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2			
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	( )	( )	( )
D. End of Term Costs	4			

PacifiCorp's Initial Transaction with California Utility

Name of parties:

Term of Contract:

Date of Execution:

Amount of Transaction (MW):

(PMLAN-MPSD-W:\PMT\CT94628EXJ.DOC)

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

SEP 26 1994

In reply refer to: PMT

Amendatory Agreement No. 1
Contract No. DE-MS79-94BP94524

Mr. Steven J. Klein
Light Division Superintendent
City of Tacoma, Department of Public Utilities
3628 South 35th Street
Tacoma, WA 98411

Dear Mr. Klein:

This letter constitutes an agreement between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (Bonneville) and the City of Tacoma, Department of Public Utilities (Tacoma), a municipal corporation operating and existing under the laws of the State of Washington, to amend Contract No. DE–MS79–94BP94524 (Capacity Ownership Agreement), executed by Tacoma on September 23, 1994. This letter agreement shall be effective upon the Effective Date of the Capacity Ownership Agreement and shall have the same term as the Capacity Ownership Agreement.

Bonneville and Tacoma agree that subparagraphs 3(b)(2)(A) and 3(b)(2)(B) in the Capacity Ownership Agreement shall be deleted and the following language shall be substituted:

(A) Tacoma may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Tacoma. Tacoma agrees to provide Bonneville access to its available unused Scheduling Share on any hour under terms and conditions comparable to those provided by Bonneville to Tacoma under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto.

(B) Tacoma hereby waives any rights it may have under Exhibit B of the Long-Term Intertie Access Policy as Exhibit B existed on June 30, 1994, and any rights to access under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto. Tacoma does not waive any other rights it may have to transmission access on Bonneville's PNW-PSW Intertie including but not limited to: (1) firm transmission service on Bonneville's PNW-PSW Intertie; (2) transmission service under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or

amendments thereto; or (3) any rights to request an order from the Federal Energy Regulatory Commission under Section 211, or any other applicable section, of the Federal Power Act or any successor statute, requiring Bonneville to provide transmission service to Tacoma consistent with the above.

Tacoma and Bonneville agree to negotiate in good faith the terms and conditions under which Tacoma shall be able to access Bonneville's PNW-PSW Intertie under the condition 1 provisions of section 5(c)(1) of Bonneville's Long-Term Intertie Access Policy as it existed on June 30, 1994.

In order for Bonneville to implement the changes to (A) and (B) reflected above, a new paragraph 3(b)(2)(D) needs to be added to the Capacity Ownership Agreement. The language follows:

(D) Bonneville shall not be obligated to provide wheeling under the open market provisions of section 5(c)(2) of Bonneville's Long-Term Intertie Access Policy, including any revisions or amendments thereto, until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Tacoma or until December 27, 1994, which ever occurs sooner.

Further, the following amendments to subsection 4(a) are made. Delete the phrase "(and only Tacoma)" in the first sentence. Before the first sentence, insert the following three sentences: "For purposes of this section 4, all references to Tacoma shall mean Tacoma or its designee. Any such designee shall be identified in writing by Tacoma to Bonneville. Only one entity may submit schedules on Tacoma's behalf at any one time."

In addition, the following amendment to Exhibit E, paragraph B, is made. Delete the phrase "subparagraph 3(b)(1)(C)" and replace it with the phrase "subparagraph 3(b)(1)(C) or 3(b)(2)(B)."

If the foregoing terms are acceptable to Tacoma, please sign and return one copy of this letter agreement. The remaining copy is for your files.

Sincerely,

Walter E. Pollock
Group Vice President, Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

ACCEPTED:

CITY OF TACOMA, DEPARTMENT OF PUBLIC UTILITIES

By _____

Name Steven J. Klein
(Print/Type)

Title Deputy Director/Light Superintendent

Date 10/27/94

Effective Date September 27, 1994

(PMLAN-W:\PMT\CONTRACT\LTR_AGMT\94524AM1.DOC)

Approved as to form & legality

_____
Chief Asst. City Attorney

AUTHENTICATED COPY Contract No. DE-MS79-94BP94524

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

CITY OF TACOMA, DEPARTMENT OF PUBLIC UTILITIES

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Tacoma's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the CITY OF TACOMA, DEPARTMENT OF PUBLIC UTILITIES (Tacoma), a municipal corporation operating and existing under the laws of the state of Washington. Each of Bonneville and Tacoma is sometimes referred to individually in this Agreement as "Party"; Bonneville and Tacoma are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Tacoma executed a Memorandum of Understanding, DE-MS79-91BP93468, dated September 23, 1991, which, among other things, sets forth the principles for Tacoma's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Tacoma are executing Contract No. DE-MS79-94BP93936 to provide Tacoma with, among other things, network wheeling between the John Day Substation and Tacoma's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Tacoma agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Tacoma's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Tacoma) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Tacoma) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Tacoma pursuant to this Agreement, which percentage is determined by dividing Tacoma's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Tacoma pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Tacoma pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Tacoma's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as

amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Tacoma to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Tacoma.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Tacoma for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Tacoma for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Tacoma's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Tacoma pursuant to this Agreement, which percentage is determined by dividing Tacoma's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Tacoma's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Tacoma.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Tacoma until payment is made by Tacoma pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Tacoma pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Tacoma written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Tacoma pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H,

and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Tacoma, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Tacoma purchases from Bonneville and Bonneville sells to Tacoma the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, Tacoma shall notify Bonneville in writing of Tacoma's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Tacoma shall have the right to utilize its Scheduling Share pursuant to the paragraph Tacoma elects. Prior to Bonneville's receipt of such notification, Tacoma shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Tacoma fails to make an election within the prescribed time period, Tacoma shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) No Third Party Wheeling

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Tacoma shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Tacoma does not own at the California-Oregon border or for which transmission Tacoma receives any revenue that would be reportable in

Tacoma's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Tacoma's Scheduling Share is not fully utilized by Tacoma in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Tacoma's Scheduling Share for such hour but no longer than such hour. Tacoma shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Tacoma's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Tacoma has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Tacoma's Scheduling Share. In return for Tacoma's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Tacoma

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Tacoma's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-

north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Tacoma's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Tacoma's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Tacoma's Scheduling Share for such hour is less than the MW amount of the aggregate of Tacoma's net firm transactions identified by Tacoma to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Tacoma's firm transactions that equals the difference between Tacoma's Scheduling Share for such hour and

the MW amount of the aggregate of Tacoma's firm transactions for such hour up to, but not in excess of, Tacoma's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Tacoma is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Tacoma shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Tacoma pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Tacoma pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Tacoma or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Tacoma shall identify such firm transaction to Bonneville. Tacoma shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Tacoma's contract for such firm transaction (after information considered proprietary by Tacoma has been redacted by Tacoma). Bonneville shall review such contract to verify that the transaction is firm. If Tacoma and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Tacoma retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Tacoma may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Tacoma. Tacoma shall have no obligation under this Agreement to make available to Bonneville any portion of Tacoma's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Tacoma's Scheduling Share without Tacoma's prior consent.

(B) Tacoma hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Tacoma with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Tacoma shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Tacoma uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Tacoma (and only Tacoma) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Tacoma's Scheduling Share for such hour. The MW amount of Tacoma's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Tacoma's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Tacoma shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Tacoma on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Tacoma of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Tacoma no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Tacoma no later than 0930 hours

on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Tacoma shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Tacoma shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Tacoma shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and

other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Tacoma's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Tacoma's schedule exceeds Tacoma's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. UPGRADES

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Tacoma information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Tacoma in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges

other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Tacoma's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Tacoma's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Tacoma may elect to acquire a share of such Upgrade in an amount up to Tacoma's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Tacoma shall notify Bonneville in writing of Tacoma's decision regarding such acquisition. If Tacoma elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Tacoma's notice to Bonneville shall include the percentage of such Upgrade that Tacoma elects to acquire (Acquisition Percentage). If Tacoma fails to notify Bonneville within such 100-day period, Tacoma shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Tacoma elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Tacoma shall be Tacoma's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Tacoma shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Tacoma's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Tacoma and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership

Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Tacoma and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Tacoma may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Tacoma such portion of the Unacquired Share as has been apportioned to Tacoma pursuant to the Apportionment, and Bonneville shall offer to Tacoma such portion of the Unacquired Share.

(2) If Bonneville does not receive from Tacoma and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Tacoma and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = Tacoma's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Tacoma's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Tacoma shall

notify Bonneville in writing of Tacoma's decision regarding acquisition of the Additional Share Offered. If Tacoma fails to notify Bonneville within such 30-day period, Tacoma shall be deemed to have elected not to acquire any of the Additional Share Offered. If Tacoma elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Tacoma shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Tacoma elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Tacoma with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Tacoma pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Tacoma shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Tacoma has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Tacoma's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Tacoma's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Tacoma to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Tacoma in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Tacoma to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Tacoma's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Tacoma of the entire Agreement and of all of Tacoma's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Tacoma of this Agreement or of any of Tacoma's rights under this Agreement as

security for any indebtedness, whether present or future, of Tacoma pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Tacoma and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Tacoma has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Tacoma shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Tacoma transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Tacoma shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC

Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Tacoma's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Tacoma in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Tacoma in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Tacoma's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement

Cost for such Reinforcement between Bonneville and Tacoma based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Tacoma have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Tacoma pursuant to this subsection 7(d) shall not be payable by Tacoma pursuant to this Agreement.

(e) Bonneville shall provide Tacoma notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on Tacoma's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Tacoma's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Tacoma's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Tacoma's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c),

or 11(a) without Tacoma's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Tacoma hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Tacoma shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Tacoma in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Tacoma for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Tacoma shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Tacoma agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Tacoma, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Tacoma shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Tacoma, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of

Bonneville and Tacoma agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Tacoma pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Tacoma pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Tacoma a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Tacoma shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Tacoma, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to

the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Tacoma agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Tacoma pursuant to paragraph 9(a)(1), Bonneville shall bill Tacoma on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Tacoma shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Tacoma pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Tacoma on the monthly power bill, and Tacoma shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being

hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Tacoma the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Tacoma written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Tacoma an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in

Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Tacoma on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Tacoma shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Tacoma an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B,

D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to Tacoma on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Tacoma shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Tacoma pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Tacoma or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Tacoma on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Tacoma shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Tacoma the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Tacoma an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Tacoma such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Tacoma shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Tacoma an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Tacoma such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Tacoma shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Tacoma pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term

"AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Tacoma for wheeling provided pursuant to section 3(b)(1)(C)(i) on Tacoma's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Tacoma shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Tacoma shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Tacoma's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Tacoma pursuant to section 4 without incurring any liability to Tacoma therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Tacoma of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Tacoma makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Tacoma shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Tacoma shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Tacoma pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Tacoma pursuant to this Agreement; provided, however that Tacoma's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect

to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Tacoma pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Tacoma pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Tacoma, in a lump sum, any refund due to Tacoma pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Tacoma pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Tacoma under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Tacoma by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Tacoma, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Tacoma from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Tacoma's power bill.

10. **TRANSMISSION LOSSES**

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Tacoma pursuant to this Agreement, Tacoma shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Tacoma and

Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Tacoma's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Tacoma's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Tacoma's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Tacoma's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Tacoma in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written

notice to Tacoma of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Tacoma for purposes of effectuating remedial actions pursuant to this section.

(b) **Tacoma's Responsibilities**

(1) Tacoma shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Tacoma's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm Tacoma's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Tacoma shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Tacoma's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Tacoma pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be

determined by dividing the amount of power scheduled by Tacoma on Tacoma's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Tacoma shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Tacoma's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Tacoma and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Tacoma pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Tacoma may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Tacoma fails to appoint a representative to the Committee, Tacoma waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Tacoma hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Light Division Superintendent

Alternate: Power Manager

(b) **Convening Meetings**

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Power Manager
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Tacoma, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Tacoma, and Tacoma shall not have any obligation

pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection

13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Tacoma and Capacity Owners other than Tacoma and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss

factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for

documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Tacoma's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into

good faith negotiations with Tacoma and Capacity Owners other than Tacoma regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Tacoma's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Tacoma is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Tacoma shall act through the Committee. Each of Bonneville and Tacoma agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that

has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Tacoma,

respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Tacoma each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no

authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Tacoma shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Tacoma its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or

controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Tacoma or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Tacoma pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Tacoma's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B,

lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating

Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration

within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Tacoma, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one.

The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or

information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not

otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Tacoma and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months

after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Tacoma pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Tacoma pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Tacoma or any Capacity Owner other than Tacoma for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville

shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Tacoma a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Tacoma a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Tacoma as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Tacoma's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Tacoma.

(f) If an audit report provided to Bonneville by Tacoma pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any

inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Tacoma a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Tacoma a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Tacoma as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Tacoma's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Tacoma; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Tacoma shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Tacoma chooses not to participate in any audit undertaken by the Committee, then Tacoma shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits

shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Tacoma of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Tacoma is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Tacoma's books, records, and documents that directly pertain to the revenue reportable in Tacoma's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Tacoma shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Tacoma is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Tacoma has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or

energy to Tacoma or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Tacoma at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Tacoma may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Tacoma may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Tacoma may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Tacoma's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Tacoma has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Tacoma's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Tacoma's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Tacoma' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Tacoma's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Tacoma of the amount of the Refunded Lump Sum Payment.

If Tacoma elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would

inequitably allocate to Tacoma and Capacity Owners other than Tacoma, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Tacoma or any Capacity Owner other than Tacoma.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Tacoma may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Tacoma may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Tacoma may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Tacoma's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Tacoma has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Tacoma's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the

immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Tacoma of the amount of Refunded Lump Sum Payment.

If Tacoma elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Tacoma and Capacity Owners other

than Tacoma, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Tacoma or any Capacity Owner other than Tacoma.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Tacoma, and Capacity Owners other than Tacoma shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Tacoma in substantially the same position with respect to Tacoma's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Tacoma, and Capacity Owners other than Tacoma shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Tacoma, and Capacity Owners other than Tacoma reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such

Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Tacoma, and Capacity Owners other than Tacoma do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Tacoma and Capacity Owners other than Tacoma and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Tacoma, and Capacity Owners other than Tacoma are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Tacoma may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Tacoma's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Tacoma elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Tacoma shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-

PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Tacoma's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Tacoma a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Tacoma's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Tacoma's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Tacoma pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Tacoma to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Tacoma to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Tacoma of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Tacoma's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Tacoma fails to

terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Tacoma shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Tacoma shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Tacoma and Capacity Owners other than Tacoma. If Bonneville and Tacoma do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Tacoma, and Tacoma shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final

basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Tacoma's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of

Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Tacoma and Capacity Owners other than Tacoma.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and Tacoma agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Power Manager
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. **WAIVER**

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. **MISCELLANEOUS**

(a) **Effect of Section Headings**

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Tacoma shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or

any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Tacoma an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Tacoma during the development or consideration of any offer to any Capacity Owner other than Tacoma to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Tacoma is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Tacoma's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the

case may be, by the Committee, and not by Tacoma acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September

Date September 27, 1994

City of Tacoma, Department of Public Utilities

By Mark Crisson

Name Mark Crisson
(Print/Type)

Title Director of Utilities

Date September 23, 1994

Approved as to form & legality:

Chief Asst. City Attorney

/s/ MARK BUBENIK
Chief Assistant City Attorney

Effective Date September 27, 1994

/s/ MARK CRISSON

Director of Utilities

September 23, 1994

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$KK)} * \%}{\text{725 MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	41 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual	(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1. Alvey (Marion-Alvey Caps)	$5,739		
2. Slatt (Loop in - Breaker)	3,044		
3. Grizzly (BPA Breakers)	11,044		
4. Loop into Slatt	656		
5. Malin-Meridian loop into Captain Jack	982		
6. Alvey Substation - BPA	8,168		
7. Dixonville - PacifiCorp	8,635		
8. Meridian - PacifiCorp	6,548		
9. Power System Control	3,575		
10. Alvey-Spencer - BPA	1,346		
11. Spencer-Dixonville - PacifiCorp	20,388		
12. Dixonville-Meridian - PacifiCorp	32,140		
SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent			
13. Captain Jack (BPA Breakers)	$14,335		
14. Captain Jack (Communication and Control)	5,100		
15. Captain Jack (Series Capacitors)	722		
16. Power System Control	5,596		
17. Captain Jack line to Oregon-Calif. border	5,724		
SUBTOTAL	$31,477		
50 PERCENT OF SUBTOTAL	15,739		
TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Tacoma's Capacity Ownership Share	=	41 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$8,815,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	0
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Tacoma submitted a letter of credit.

D. ADJUSTED LUMP SUM PAYMENT

1.	Tacoma's Capacity Ownership Share	=		41 MW
2.	Adjusted Capacity Ownership Price	X	$	
3.	Adjusted Lump Sum Payment[1]	=		
4.	Initial Lump Sum Payment	–		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Tacoma	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Tacoma	=		

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Tacoma receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Tacoma's Capacity Ownership Share	=		41 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Tacoma	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Tacoma	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Tacoma receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Tacoma receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Tacoma receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Tacoma's schedules for transactions transmitted on Tacoma's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Tacoma's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Tacoma, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Tacoma and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Tacoma and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Tacoma or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Tacoma or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Tacoma and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Tacoma has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Tacoma shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Tacoma shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Tacoma agrees as follows:

(1) Tacoma shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Tacoma shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Tacoma shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Tacoma shall, in all solicitations or advertisements for employees placed by or on behalf of Tacoma, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Tacoma shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Tacoma's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Tacoma shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Tacoma shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Tacoma shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Tacoma's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Tacoma is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Tacoma may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Tacoma as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Tacoma shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Tacoma shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Tacoma becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Tacoma may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Tacoma certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Tacoma agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Tacoma agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Tacoma to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Tacoma hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Tacoma further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Tacoma's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Tacoma shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Tacoma acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Tacoma agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Tacoma agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Tacoma and Bonneville shall, in concert with the Capacity Owners other than Tacoma, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III: Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Tacoma pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D; line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Tacoma shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1			
MFUs of the FCRTS	2			
Allocation factor (Line 1/Line 2)	3			
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4			
Bonneville's total system operations cost from rate case	5			
Operations functionalization factor (Line 4/Line 5)	6			
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7			
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8			

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1			
Total power scheduling cost from rate case	2			
Power scheduling cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Power Scheduling Costs				
Power scheduling direct costs	5			
Power scheduling indirect costs	6			
Power scheduling overhead costs	7			
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8			
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9			

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	_____	_____	_____
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(_____)	(_____)	(_____)
D. End of Term Costs	4	_____	_____	_____

Tacoma's Initial Transaction with California Utility

Name of parties:	Tacoma / Western Area Power Administration
Term of Contract	December 31, 2004
Date of Execution:	December 31, 1984
Amount of Transaction (MW):	41 MW, December through August 74 MW, September through November

AUTHENTICATED COPY Contract No. DE-MS79-94BP94522

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF SEATTLE, WASHINGTON

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Seattle's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of September 27, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and the CITY OF SEATTLE, CITY LIGHT DEPARTMENT, (Seattle), a municipal corporation operating and existing under the laws of the state of Washington. Each of Bonneville and Seattle is sometimes referred to individually in this Agreement as "Party"; Bonneville and Seattle are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Seattle executed a Memorandum of Understanding, DE-MS79-91BP93467 , dated September 18, 1991, which, among other things, sets forth the principles for Seattle's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Seattle are executing an amendment to Contract No. DE-MS79-88BP91657 to provide Seattle with, among other things, network wheeling between the John Day Substation and Seattle's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Seattle agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Seattle's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Seattle) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Seattle) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Seattle pursuant to this Agreement, which percentage is determined by dividing Seattle's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Seattle pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Seattle pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Seattle's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with

the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Seattle to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Seattle.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Seattle for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Seattle for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Seattle's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Seattle pursuant to this Agreement, which percentage is determined by dividing Seattle's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Seattle's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Seattle.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the date of execution and delivery of this Agreement by both of the Parties. This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Seattle until payment is made by Seattle pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Seattle pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Seattle written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Seattle pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H,

and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Seattle, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Seattle purchases from Bonneville and Bonneville sells to Seattle the Capacity Ownership Rights.

(b) Right to Wheel for Third Parties

No later than 30 days after the Effective Date, Seattle shall notify Bonneville in writing of Seattle's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Seattle shall have the right to utilize its Scheduling Share pursuant to the paragraph Seattle elects. Prior to Bonneville's receipt of such notification, Seattle shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Seattle fails to make an election within the prescribed time period, Seattle shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) No Third Party Wheeling

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Seattle shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Seattle does not own at the California-Oregon border or for which transmission Seattle receives any revenue that would be reportable in

Seattle's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Seattle's Scheduling Share is not fully utilized by Seattle in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Seattle's Scheduling Share for such hour but no longer than such hour. Seattle shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Seattle's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Seattle has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis, any transaction for such hour on any MW amount of Seattle's Scheduling Share. In return for Seattle's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Seattle

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Seattle's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-

north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Seattle's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Seattle's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Seattle's Scheduling Share for such hour is less than the MW amount of the aggregate of Seattle's net firm transactions identified by Seattle to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Seattle's firm transactions that equals the difference between Seattle's Scheduling Share for such hour and the

MW amount of the aggregate of Seattle's firm transactions for such hour up to, but not in excess of, Seattle's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Seattle is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Seattle shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Seattle pursuant to section 3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Seattle pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Seattle or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Seattle shall identify such firm transaction to Bonneville. Seattle shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Seattle's contract for such firm transaction (after information considered proprietary by Seattle has been redacted by Seattle). Bonneville shall review such contract to verify that the transaction is firm. If Seattle and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Seattle retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Seattle may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Seattle. Seattle shall have no obligation under this Agreement to make available to Bonneville any portion of Seattle's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Seattle's Scheduling Share without Seattle's prior consent.

(B) Seattle hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Seattle with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Seattle shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Seattle uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Seattle (and only Seattle) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Seattle's Scheduling Share for such hour. The MW amount of Seattle's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Seattle's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Seattle shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) **Preschedules**

(A) Bonneville shall make available to Seattle on each Working Day as soon as practicable after 0800 hours information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Seattle of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Seattle no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Seattle no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Seattle shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Seattle shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Seattle shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of

coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Seattle's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Seattle's schedule exceeds Seattle's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. **UPGRADES**

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Seattle information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Seattle in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Seattle's Capacity Ownership Percentage multiplied

by the MW amount of such Upgrade and (B) Seattle's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Seattle may elect to acquire a share of such Upgrade in an amount up to Seattle's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Seattle shall notify Bonneville in writing of Seattle's decision regarding such acquisition. If Seattle elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Seattle's notice to Bonneville shall include the percentage of such Upgrade that Seattle elects to acquire (Acquisition Percentage). If Seattle fails to notify Bonneville within such 100-day period, Seattle shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Seattle elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Seattle shall be Seattle's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Seattle shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Seattle's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Seattle and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Seattle and each of such other Capacity Owners

have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Seattle may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Seattle such portion of the Unacquired Share as has been apportioned to Seattle pursuant to the Apportionment, and Bonneville shall offer to Seattle such portion of the Unacquired Share.

(2) If Bonneville does not receive from Seattle and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Seattle and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A \div B) \times C$

where: A = Seattle's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Seattle's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Seattle shall notify Bonneville in writing of Seattle's decision regarding acquisition of the Additional Share Offered. If Seattle fails to notify Bonneville within such 30-day period, Seattle shall be deemed to have elected not to acquire any of the Additional Share

Offered. If Seattle elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Seattle shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Seattle elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Seattle with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Seattle pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Seattle shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Seattle has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Seattle's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Seattle's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Seattle to any person without Bonneville's prior and express written consent. Such consent shall not be

unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Seattle in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Seattle to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Seattle's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Seattle of the entire Agreement and of all of Seattle's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Seattle of this Agreement or of any of Seattle's rights under this Agreement as security for any indebtedness, whether present or future, of Seattle pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Seattle and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Seattle has defaulted in the

performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Seattle shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Seattle transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Seattle shall give Bonneville written notice of such transfer, sale, alienation, or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Seattle's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie,

and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Seattle in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability change substantially, Bonneville shall notify Seattle in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Seattle's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Seattle based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this

subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Seattle have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Seattle pursuant to this subsection 7(d) shall not be payable by Seattle pursuant to this Agreement.

(e) Bonneville shall provide Seattle notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on Seattle's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Seattle's interests to the extent such interests have been expressed to Bonneville in writing.

8. **EXISTING AGREEMENTS**

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Seattle's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Seattle's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Seattle's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Seattle hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements

with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Seattle shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Seattle in accordance with the provisions of this section 9.

(a) Lump Sum Payment

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Seattle for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Seattle shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Seattle agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of

Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Seattle, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Seattle shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Seattle, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Seattle agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Seattle pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Seattle pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Seattle a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and

such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Seattle shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Seattle, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Seattle agrees

that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Seattle pursuant to paragraph 9(a)(1), Bonneville shall bill Seattle on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Seattle shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Seattle pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Seattle on the monthly power bill, and Seattle shall pay, pursuant to Exhibit B, forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual

Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year, Bonneville shall refund to Seattle the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Seattle written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Seattle an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast

Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Seattle on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Seattle shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Seattle an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant

Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year, Bonneville shall bill to Seattle on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Seattle shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Seattle pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of

the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but excluding) the date of refund to Seattle or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Seattle on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Seattle shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the

forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Seattle the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Seattle an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Seattle such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Seattle shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Seattle an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent

of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Seattle such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Seattle shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Seattle pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate

shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Seattle for wheeling provided pursuant to section 3(b)(1)(C)(i) on Seattle's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Seattle shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Seattle shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Seattle's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Seattle pursuant to section 4 without incurring

any liability to Seattle therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Seattle of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Seattle makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Seattle shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Seattle shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Seattle pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Seattle pursuant to this Agreement; provided, however that Seattle's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Seattle pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the

month in which such payment becomes due to Seattle pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Seattle, in a lump sum, any refund due to Seattle pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Seattle pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Seattle under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Seattle by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Seattle, (B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Seattle from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Seattle's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Seattle pursuant to this Agreement, Seattle shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Seattle and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Seattle's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Seattle's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Seattle's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Seattle's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Seattle in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Seattle of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by

Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Seattle for purposes of effectuating remedial actions pursuant to this section.

(b) **Seattle's Responsibilities**

(1) Seattle shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Seattle's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville may perform engineering analyses to confirm Seattle's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Seattle shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Seattle's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Seattle pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Seattle on Seattle's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Seattle shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Seattle's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Seattle and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Seattle pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Seattle may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Seattle fails to appoint a representative to the Committee, Seattle waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Seattle hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Director, Power Management Division

Alternate: Manager, Resource Operations

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee

pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Seattle, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Seattle, and Seattle shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for

each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Seattle and Capacity Owners other than Seattle and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily

available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee

and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its

receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which

Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an

Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan (either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such

Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Seattle's rights and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the

Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Seattle and Capacity Owners other than Seattle regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such

recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners

with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Seattle's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Seattle is obligated to pay pursuant to the terms and conditions of this Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Seattle shall act through the Committee. Each of Bonneville and Seattle agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator

within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Seattle, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the

arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Seattle each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan

becomes effective pursuant to subsection 13(j), then Seattle shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Seattle its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to $1 \div (n + 1)$, where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning

any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Seattle or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Seattle pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Seattle's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation

Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Seattle, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one. The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the

name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as

amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes

regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is

made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Seattle and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15

equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Seattle pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Seattle pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Seattle or any Capacity Owner other than Seattle for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Seattle a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either

(A) render to Seattle a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Seattle as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Seattle's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Seattle.

(f) If an audit report provided to Bonneville by Seattle pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Seattle a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted

Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Seattle a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Seattle as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Seattle's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Seattle; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to

the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Seattle shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Seattle chooses not to participate in any audit undertaken by the Committee, then Seattle shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards. Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Seattle of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Seattle is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Seattle's books, records, and documents that directly pertain to the revenue reportable in Seattle's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Seattle shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Seattle is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Seattle has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Seattle or by a seller of power or energy, which power or energy is not resource-specific and is delivered to Seattle at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Seattle may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Seattle may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Seattle may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Seattle's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Seattle has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Seattle's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + I = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Seattle's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Seattle' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which

Bonneville receives Seattle's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Seattle of the amount of the Refunded Lump Sum Payment.

If Seattle elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would inequitably allocate to Seattle and Capacity Owners other than Seattle, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Seattle or any Capacity Owner other than Seattle.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and

if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Seattle may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Seattle may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Seattle may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Seattle's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Seattle has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Seattle's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal

monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Seattle of the amount of Refunded Lump Sum Payment.

If Seattle elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Seattle and Capacity Owners other than Seattle, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Seattle or any Capacity Owner other than Seattle.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval

to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Seattle, and Capacity Owners other than Seattle shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Seattle in substantially the same position with respect to Seattle's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Seattle, and Capacity Owners other than Seattle shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Seattle, and Capacity Owners other than Seattle reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Seattle, and Capacity Owners other than Seattle do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Seattle and Capacity Owners other than Seattle and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Seattle, and Capacity Owners other than Seattle are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Seattle may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Seattle's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Seattle elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Seattle shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Seattle's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Seattle a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Seattle's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered

by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Seattle's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Seattle pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Seattle to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Seattle to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Seattle of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Seattle's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Seattle fails to terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Seattle shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final

basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Seattle shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Seattle and Capacity Owners other than Seattle. If Bonneville and Seattle do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Seattle, and Seattle shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis. Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Seattle's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses

incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Seattle and Capacity Owners other than Seattle.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. RULES OF LAW

(a) Bonneville and Seattle agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. WAIVER

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. MISCELLANEOUS

(a) Effect of Section Headings

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) Amendments

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of

dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Seattle shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Seattle an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Seattle during the development or consideration of any offer to any Capacity Owner other than Seattle to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Seattle is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Seattle's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Seattle acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By _____
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

September 27, 1994

Date September 27, 1994

The City of Seattle

By _____

/s/ ROBERTA PALM BRADLEY

Name Roberta Palm Bradley
(Print/Type)

Title Superintendent

Superintendent

Date September 23, 1994

September 23, 1994

Effective Date September 27, 1994

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville's PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the rated transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meridian

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment, if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$(XX)) * \%}}{\text{725 MW * \# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacements Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 15 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent), shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	160 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual		(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Seattle's Capacity Ownership Share	=	160 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$34,400,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Seattle. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Seattle's Capacity Ownership Share	=	160 MW
2.	Adjusted Capacity Ownership Price	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Seattle	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Seattle	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Seattle receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Seattle's Capacity Ownership Share	=		160 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$	
3.	Current Revised Adjusted Lump Sum Payment[1]	=		
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-		_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Seattle	=		
6.	Interest[2]	+		
7.	Due to Bonneville, or Refund due to Seattle	=		

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Seattle receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Seattle receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Seattle receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Seattle's schedules for transactions transmitted on Seattle's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Seattle's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976) Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	180 MVAR Reactor Bank No. 1	100	100
	• Breaker D#4222	100	100
	• Isolating Switch D#4060	100	100
	• Associated Arresters	100	100
	300 MVAR Reactor Bank No. 2	100	100
	• Breaker D#4720	100	100
	• Isolating Switch D#4719	100	100
	• Associated Arresters	100	100
	• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
	• Breaker D#4038	100	100
	• Isolating Switch D#4062	100	100
	• Neutral isolating switch D#4109/4081	100	100
	• Associated Arresters	100	100
	• Associated PTs	100	100
	• North Main Bus 500 kV PTs	100	100
	• South Main Bus 500 kV PTs	100	100
	Station General		
9.	**Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
	Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
10.	**Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
	Station General		
11.	**Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
Station General		
12. **Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
• Breaker D#4959	100	57
• MOD D#4955	100	57
• MOD D#4956/7309	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Malin line terminal		
• Line protective relays	0	100
Station General		
13. **Malin 500 kV** (Dispatch one-line diagram No. 103923)		
Captain Jack No. 1 line terminal		
• Breaker D#4066	100	100
• Breaker D#4064	100	100
• MOD D#4068	100	100
• MOD D#4067/7849	100	100
• MOD D#4065	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 1 terminal		
• Breaker D#4186	50	100
• MOD D#4063/7970	100	100
• MOD D#4185	50	100
• MOD D#4187	50	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Seattle, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation: liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Seattle and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Seattle and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Seattle or its subcontractor, if any, under any such

contract or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Seattle or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Seattle and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If, during any 12-month period (including the 12 months preceding the award of this contract), Seattle has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Seattle shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Seattle shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Seattle agrees as follows:

(1) Seattle shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Seattle shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Seattle shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Seattle shall, in all solicitations or advertisements for employees placed by or on behalf of Seattle, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Seattle shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Seattle's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Seattle shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Seattle shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Seattle shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs (OFCCP) for purpose of investigation to ascertain Seattle's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Seattle is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Seattle may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Seattle as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Seattle shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Seattle shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Seattle becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Seattle may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Seattle certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Seattle agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Seattle agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Seattle to fund its activities pursuant to this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Seattle hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Seattle further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Seattle's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Seattle shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Seattle acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Seattle agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Seattle agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Seattle and Bonneville shall, in concert with the Capacity Owners other than Seattle, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective

equipment (such as grounding devices; reactors; arrestors and resistors; voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that

Capacity Owners pay only transmission-related system operations costs. The operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation

of the Federal transmission system; load, frequency, and voltage control of Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are

consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control

maintenance; nonelectric plant maintenance; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred

by Bonneville in connection with the performance of any of the following activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities

undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies

employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services;

area offices; operations, maintenance, and construction; and engineering); and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Seattle pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements

referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Seattle shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Seattle's Initial Transaction with California Utility

Name of parties:	(1) Seattle / Pacific Gas & Electric Company
	(2) Seattle / Northern California Power Agency
Term of Contract:	(1) March 16, 2003
	(2) March 16, 2013
Date of Execution:	(1) March 16, 1993
	(2) March 16,1993
Amount of Transaction (MW):	(1) 100 MW
	(2) 60 MW

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1			
Total power scheduling cost from rate case	2			
Power scheduling cost functionalization factor (Line 1/Line 2)	3			
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4			
C. Total Power Scheduling Costs				
Power scheduling direct costs	5			
Power scheduling indirect costs	6			
Power scheduling overhead costs	7			
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8			
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9			

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	_____	_____	_____
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(_____)	(_____)	(_____)
D. End of Term Costs	4	_____	_____	_____

AMENDATORY AGREEMENT

to the

PACIFIC NORTHWEST AC INTERTIE

CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUGET SOUND POWER& LIGHT COMPANY

Section Page

1. Definitions 2
2. Amendment of Agreement 2

This AMENDATORY AGREEMENT is executed as of Dec 20 1996, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PUGET SOUND POWER & LIGHT COMPANY **(Puget),** a corporation of the State of Washington.

WI TN ES SETH:

WHEREAS the Parties on October 11, 1994, entered into the Pacific Northwest (PNW) AC Intertie Capacity Ownership Agreement, Contract No. DE-MS79-94BP94521 (Agreement); and

WHEREAS the Federal Energy Regulatory Commission (FERC) has issued Order No. 888, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities And Transmitting Utilities"; and

WHEREAS the Parties desire to amend the Agreement so as to comply with such Order No. 888,

NOW, THEREFORE, the Parties agree as follows:

1. DEFINITIONS

Capitalized terms used in this Amendatory Agreement, unless otherwise defined herein, have the respective meanings set forth for such terms in the Agreement.

2. AMENDMENT OF AGREEMENT

Subsection 3(b) of the Agreement is deleted in its entirety and the following is inserted in lieu thereof

(b) Right to Wheel for Third Parties

Puget may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Puget. Puget shall have no obligation under this Agreement to make available to Bonneville any portion of Puget's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Puget's Scheduling Share without Puget's prior written consent.

Bonneville shall treat all scheduling information consistent with the standards of conduct contained in Part 37 of **FERC's** regulations.

IN WITNESS WHEREOF, the Parties hereto have executed this **Amendatory** Agreement.

PUGET SOUND POWER& LIGHT **COMPANY**

By Wayman Robinett

Name Wayman Robinett
(Print/Type)

Title Manager Transmission

Date Dec 20, 1996

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Clifford C. Perkins

Name Clifford C. Perkins
(Print/Type)

Title SR. Acct Ex.

Date 12-20-1996

PUGET POWER

December 23, 1996

Group Vice President for Marketing,
Conservation and Production
Bonneville Power Administration
905 NE 1 lth Avenue
Portland, OR 97232

Attention: Cliff Perigo
Senior Account Executive

Subject: Amendment to Puget Sound Power& Light Company (Puget) PNW AC Intertie Capacity Ownership Agreemeut

Dear Mr. Perigo:

Enclosed for your signature are two original copies, each signed by Puget, of an Amendatory Agreement to Puget's PNW AC Intertie Capacity Ownership Agreement, Contract No. DE-MS79-94BP94521. On December 20, 1996, Puget and Bonneville Power Administration entered into the Amendatory Agreement by signing and exchanging a facsimile copy of the enclosed originals.

This amendment was requested by Puget in order to meet the requirement that public utilities that jointly own interstate transmission facilities with non-jurisdictional utilities offer transmission service over their share of the joint facilities. The requirement is contained in the Federal Energy Regulatory Commission Order No. 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities."

Please sign both originals and return one set to Puget.

Sincerely,

Puget Sound Power & Light Company

By Wayman L Robinett
Wayman L. Robinett
Its: Manager, Transmission

Enclosures

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94521

PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PUGET SOUND POWER & LIGHT COMPANY

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Exhibit A (CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions)
Exhibit B (Annual Costs Rate)
Exhibit C (Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share)
Exhibit D (Lump Sum Payment Calculation)
Exhibit E (Transmission Loss Factors)
Exhibit F (Bonneville's PNW AC Intertie)
Exhibit G (Capacity Owners)
Exhibit H (Provisions Required by Statute or Executive Order)
Exhibit I (Bonneville's PNW AC Intertie Costs)
Exhibit J (Puget's Initial Transaction with California Utility)

This PNW AC INTERTIE CAPACITY OWNERSHIP AGREEMENT (Agreement) is entered into as of October 11, 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville or BPA) and PUGET SOUND POWER & LIGHT COMPANY (Puget), a corporation of the state of Washington. Each of Bonneville and Puget is sometimes referred to individually in this Agreement as "Party"; Bonneville and Puget are sometimes referred to together in this Agreement as "Parties."

WITNESSETH:

WHEREAS Bonneville, Portland General Electric Company (Portland), and PacifiCorp Electric Operations (PacifiCorp) planned and constructed improvements and additions to the Northwest portion of the PNW-PSW Intertie; and

WHEREAS such construction was completed in December 1993 resulting in 1600 MW of additional PNW AC Intertie Rated Transfer Capability in a north-to-

south direction and 1225 MW of additional PNW AC Intertie Rated Transfer Capability in a south-to-north direction; and

WHEREAS pursuant to the Northwest Intertie Agreements, Bonneville operates the PNW AC Intertie, in coordination with Portland and PacifiCorp, as a single system so as to maximize PNW AC Intertie Rated Transfer Capability and Operational Transfer Capability consistent with Prudent Utility Practice; and

WHEREAS Bonneville has developed a proposal to offer to PNW non-Federal scheduling utilities and joint agencies capacity ownership rights in 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability; and

WHEREAS such proposal has been studied in Bonneville's Final Non-Federal Participation Environmental Impact Statement, dated January 1994, and was the selected alternative in the Administrator's Record of Decision, dated March 25, 1994; and

WHEREAS Bonneville and Puget executed a Memorandum of Understanding, DE-MS79-91BP93466, dated September 18, 1991, which, among other things, sets forth the principles for Puget's capacity ownership rights in Bonneville's PNW AC Intertie; and

WHEREAS interest expressed in capacity ownership by PNW non-Federal scheduling utilities and joint agencies exceeded the 725 MW of Bonneville's PNW AC Intertie Rated Transfer Capability offered by Bonneville, and as a result Bonneville developed and applied an allocation methodology selected in the Administrator's Capacity Ownership Record of Decision, dated March 25, 1994; and

WHEREAS concurrent with the execution of this Agreement, Bonneville and Puget are executing Contract No. DE-MS79-94BP93947 to provide Puget with, among other things, network wheeling between the John Day Substation and Puget's transmission system; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power generated at various Federal hydroelectric projects in the PNW, or acquired from other resources, to construct and operate transmission facilities, to provide

transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, Bonneville and Puget agree as follows:

1. **DEFINITIONS**

(a) "Adjusted Capacity Ownership Price" means the price calculated pursuant to column 2, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(b) "Adjusted Lump Sum Payment" means the Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section D of Exhibit D.

(c) "Allocated Direct Costs" means for each fiscal year the Operations Cost as allocated to Bonneville's PNW AC Intertie in accordance with section I.C of Exhibit I for such fiscal year. Allocated Direct Costs are not included in Direct Costs, Indirect Costs, or Overhead Costs.

(d) "Allowance for Funds Used During Construction" or "AFUDC" constitutes interest on the funds used for utility plant under construction. The AFUDC rate approximates the cost of money being used to finance current construction work in progress and is calculated in accordance with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors. AFUDC shall be capitalized in accordance with Bonneville's accounting procedures and practices, and in any event consistent with FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions 3.A(17), or its successors.

(e) "Billing Provisions" means those provisions set forth in Exhibit B, Part B.

(f) "Bonneville's PNW AC Intertie" means facilities of the PNW AC Intertie owned partially or entirely by Bonneville specified in Exhibit F together with the equipment and facilities installed in or connected to such facilities specified in Exhibit F, to the extent such facilities are necessary for the transmission of power on the PNW AC Intertie.

(g) "Bonneville's PNW AC Intertie Operational Transfer Capability" means Bonneville's PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and by operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(h) "Bonneville's PNW AC Intertie Rated Transfer Capability" means Bonneville's share of the PNW AC Intertie Rated Transfer Capability as determined in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(i) "Capacity Owner" means each of the parties listed in Exhibit G to the extent that such party has entered into a Capacity Ownership Agreement.

(j) "Capacity Ownership Agreement" means, in the singular, this Agreement or the agreement, substantially identical to this Agreement, entered into by each Capacity Owner (other than Puget) and Bonneville, and in the plural, this Agreement and all such substantially identical agreements entered into respectively by

Capacity Owners (other than Puget) and Bonneville, as each such agreement may be amended or supplemented from time to time pursuant to the terms of such agreement, concerning (among other things) the rights of such Capacity Owner with respect to the PNW AC Intertie.

(k) "Capacity Ownership Percentage" means, as of the Effective Date, in the singular, the percentage of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share as of the Effective Date by Bonneville's PNW AC Intertie Rated Transfer Capability as of the Effective Date (such percentage being subject to change pursuant to the terms of this Agreement), and in the plural, the percentages of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which percentages are set forth in Exhibit G (each of such percentages being subject to change pursuant to the respective terms of such Capacity Ownership Agreements).

(l) "Capacity Ownership Rights" means the rights of Puget pursuant to this Agreement.

(m) "Capacity Ownership Share" means, except as such term is otherwise used in sections III.A and III.B of the CO-94 rate set forth in Exhibit A on the Effective Date, in the singular, the MW amount of Bonneville's PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which MW amount is set forth in Exhibit C (such amount being subject to change pursuant to the terms of this Agreement), and in the plural, the MW amounts of Bonneville's PNW AC Intertie Rated Transfer Capability owned by the other Capacity Owners, respectively, pursuant to their respective Capacity Ownership Agreements (other than this Agreement), which amounts are set forth in Exhibit G (each of such amounts being subject to

change pursuant to the respective terms of such Capacity Ownership Agreements).

(n) "Committee" has the meaning set forth in subsection 12(a).

(o) "Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

(p) "Direct Costs" means any costs incurred by Bonneville which are readily identifiable, or obviously traceable to, and directly benefit, a specific Bonneville program, project, or other cost objective. Direct Costs are not included in Allocated Direct Costs, Overhead Costs, or Indirect Costs. The methods for determining Direct Costs for Bonneville's PNW AC Intertie are set forth in sections II.B and III.A of Exhibit I.

(q) "Effective Date" means the date as of which this Agreement becomes effective pursuant to section 2.

(r) "End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

(s) "FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

(t) "General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The

method for determining General Plant Cost is set forth in section IV of Exhibit I.

(u) "GTRSP" or "GTRSPs" means Bonneville's General Transmission Rate Schedule Provisions, set forth in Exhibit A, as such provisions may be revised from time to time.

(v) "Indirect Costs" means any costs incurred by Bonneville which indirectly benefit and are directly charged to a specific Bonneville program, project, or other cost objective for which a Direct Cost or Allocated Direct Cost is charged. Indirect Costs shall not be included in Allocated Direct Costs, Direct Costs, or Overhead Costs. The methods for determining Indirect Costs for Bonneville's PNW AC Intertie are set forth in sections I.D, II.D, and III.B of Exhibit I.

(w) "Initial Capacity Ownership Price" means $215 per kilowatt, the calculation of which charge is set forth in column 1, section B of Exhibit D and in section III.A of the CO-94 rate in Exhibit A.

(x) "Initial Lump Sum Payment" means the Initial Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section C of Exhibit D.

(y) "Interconnection Agreement" means the "Interim Interconnection Agreement Between Certain California-Oregon Transmission Project Participants and Northwest Participants," Contract No. DE-MS79-91BP93158, as amended or superseded.

(z) "Joint AC Intertie" is as defined in the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(aa) "Joint Intertie Scheduling Office" or "JISO" means the group of Bonneville, Portland, and PacifiCorp schedulers, which, among other things, accepts PNW-PSW Intertie Preschedules.

(bb) "Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

(cc) "MW" means megawatt.

(dd) "Northwest Intertie Agreements" means the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof.

(ee) "Operating Plan" means, subject to subsection 13(o), with respect to any fiscal year commencing on or after the day on which the annual costs rate set forth in Exhibit B has been approved on an interim or final basis by FERC, the written document containing the information described in subsection 13(c), as such document may be amended pursuant to section 13, 14, or 16.

(ff) "Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

(gg) "Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

(hh) "Overhead Cost" means administrative and general costs, support service costs, or other costs similar in nature which are distributed or allocated by Bonneville to Bonneville's PNW AC Intertie. Overhead Costs are not included in Direct Costs, Allocated Direct Costs, or Indirect Costs. The methods for determining Overhead Costs are set forth in sections I.E, II.E, and III.B of Exhibit I.

(ii) "Pacific Northwest" or "PNW" means the area defined as the Pacific Northwest in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. section 839a(14).

(jj) "Pacific Time" means Pacific Standard Time and Pacific Daylight Time as each is in force.

(kk) "PNW AC Intertie" means facilities including, but not limited to, the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line and Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, additions, improvements, or other alterations thereto.

(ll) "PNW AC Intertie Operational Transfer Capability" means the PNW AC Intertie Rated Transfer Capability as reduced by limitations beyond the control of the Parties, and operational limitations (as determined by Bonneville in accordance with the agreement between Bonneville and PacifiCorp, Contract No. DE-MS79-94BP94332, as amended from time to time pursuant to the terms thereof, and with

the agreement between Bonneville and Portland, Contract No. DE-MS79-87BP92340, as amended from time to time pursuant to the terms thereof, and in accordance with Prudent Utility Practice) resulting from, among other things, line or equipment outages, stability limits, or loopflow.

(mm) "PNW AC Intertie Rated Transfer Capability" means the north-to-south and south-to-north capability of the PNW AC Intertie to transfer power in a reliable manner as determined consistent with Prudent Utility Practice.

(nn) "Pacific Northwest-Pacific Southwest Intertie" or "PNW-PSW Intertie" means the DC transmission line between the Celilo Converter Station in The Dalles, Oregon, and the Sylmar Converter Station near Los Angeles, California, the PNW AC Intertie, and the AC Intertie in California including, without limitation, the California-Oregon Transmission Project.

(oo) "Pacific Northwest Non-Federal Utility" means any electric utility that serves retail load in the region consisting of (1) the states of Oregon, Washington, and Idaho, the portion of the state of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River Basin drainage basin, and (2) any contiguous areas, not in excess of seventy-five air miles from the area referred to in (1) above, which areas are a part of the service area of a rural electric cooperative power customer served by Bonneville on the effective date of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) having a distribution system from which it serves both within and without such region.

(pp) "Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit

I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

(qq) "Preschedule" means the schedule submitted by Puget to the JISO pursuant to paragraph 4(b)(1) for transactions prepared each Working Day for the period beginning 2400 hours of the current Working Day through 2400 hours of the next Working Day.

(rr) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto that would achieve the desired result or, if there are no such practices, methods, and acts, the practices, methods, and acts which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to achieve the desired result consistent with reliability and safety.

(ss) "Real-time Schedule" means a schedule, or change to the Preschedule, submitted during the period which begins when the Preschedule is deemed by the JISO to be complete and concludes at 2400 hours on the day for which the Preschedule is submitted by Puget.

(tt) "Reinforcement" means any transmission plant modification, addition, improvement, or other alteration to the Federal Columbia River Transmission System which is not a Replacement or an Upgrade and which is made pursuant to subsection 7(c).

(uu) "Reinforcement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on

account of such Reinforcement. Reinforcement Costs do not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(vv) "Replacement" means for any transmission plant addition, betterment, renewal and equipment or facility that takes the place of or adds to any existing equipment or facility on Bonneville's PNW AC Intertie that does not increase Bonneville's PNW AC Intertie Rated Transfer Capability.

(ww) "Replacement Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Puget for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit with respect to any PNW AC Intertie facility removed on account of such Replacement. General Plant Cost is not included in Replacement Costs. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

(xx) "Revised Adjusted Capacity Ownership Price" means a price calculated pursuant to column 3, section B of Exhibit D and section IV.B of the CO-94 rate in Exhibit A.

(yy) "Revised Adjusted Lump Sum Payment" means a Revised Adjusted Capacity Ownership Price multiplied by Puget's Capacity Ownership Share (in kilowatts), as described with more particularity in section E of Exhibit D.

(zz) "Scheduler" means the person authorized by a Party to accept or submit schedules pursuant to section 4 and authorized to implement,

interpret, and vary the scheduling procedures set forth in such section pursuant to this Agreement.

(aaa) "Scheduling Percentage" means the percentage of the PNW AC Intertie Rated Transfer Capability owned by Puget pursuant to this Agreement, which percentage is determined by dividing Puget's Capacity Ownership Share by the PNW AC Intertie Rated Transfer Capability.

(bbb) "Scheduling Share" means, for any given hour, the MW amount equal to the product of Puget's Scheduling Percentage and the PNW AC Intertie Operational Transfer Capability for such hour.

(ccc) "Scheduling Utility" means either (i) a Pacific Northwest Non-Federal Utility that serves a retail service area and operates a generation control area, or (ii) a Pacific Northwest Non-Federal Utility designated by Bonneville as a "computed requirements customer" or its equivalent.

(ddd) "Term" means the period of effectiveness of this Agreement set forth in subsection 2(a).

(eee) "Third AC Intertie" means the Third AC Intertie Project, which project increased the PNW AC Intertie Rated Transfer Capability by 1600 MW in a north-to-south direction and by 1225 MW in a south-to-north direction.

(fff) "Third AC Intertie Project" means the Third AC Intertie System Reinforcement and the construction of the Alvey-Meridian 500 kV transmission line and of facilities related to such transmission line during the period from July 1984 through December 1993.

(ggg) "Third AC Intertie System Reinforcement" means the improvements, additions and modifications to the PNW AC Intertie constructed during the period from July 1984 through December 1993 plus the construction of the Captain Jack substation and of facilities related to

such substation during the period from July 1984 through December 1993.

(hhh) "Upgrade" means any MW increase to Bonneville's PNW AC Intertie Rated Transfer Capability which arises from or is related to an increase to the PNW AC Intertie Rated Transfer Capability.

(iii) "Working Day" means any day other than Saturday, Sunday, and a legal holiday recognized by the Federal government or Puget.

2. **TERM AND TERMINATION**

(a) This Agreement shall become effective as of the later of (1) the date of execution and delivery of this Agreement by both of the Parties, and (2) the date by which this Agreement has, with respect to Puget, been approved, accepted for filing or otherwise permitted to become effective by FERC; provided, that if FERC approves this Agreement for filing or otherwise permits this Agreement to become effective with any change or new condition, this Agreement shall not be or become effective unless both of the Parties have agreed in writing, and until the date by which both of the Parties have so agreed to such change or new condition. To the extent Puget is required to submit this Agreement to FERC, Puget shall submit this Agreement to FERC for approval no later than three Working Days after the date on which this Agreement is executed and delivered by both Parties. Bonneville shall provide Puget with a copy of the executed Agreement on the next Working Day after Bonneville executes the Agreement. Without limiting any of the foregoing, Puget shall use best efforts to obtain from FERC on the earliest possible date (following the date on which Puget is required to submit this Agreement to FERC pursuant to this subsection 2(a)) FERC's acceptance for filing or permission that this Agreement become effective in accordance with this subsection 2(a). This Agreement shall continue in effect so long as any facilities of the PNW AC Intertie are in existence and operable, unless otherwise earlier terminated by written agreement of both of the Parties or unless terminated pursuant to the terms of this Agreement. All

liabilities incurred under this Agreement shall be preserved until satisfied.

(b) Notwithstanding subsection 2(a), no Capacity Ownership Rights may be exercised by Puget until payment is made by Puget pursuant to paragraph 9(a)(1) and received by Bonneville.

(c) If Bonneville does not receive the payment from Puget pursuant to paragraph 9(a)(1), then Bonneville shall have the option to terminate this Agreement by delivering to Puget written notice of such termination.

(d) Notwithstanding subsection 2(a), if Bonneville incurs End of Term Costs, the following provisions of this Agreement, and all rights and obligations thereunder, shall continue in full force and effect until Bonneville renders its final bill to Puget pursuant to subsection 9(b), unless this Agreement is earlier terminated by mutual agreement of the Parties: subsections 2(b), 2(c), and 2(d), sections 1, 7, 8, 9, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, and 23, and Exhibits A, B, C, D, F, G, H, and I. All liabilities incurred under such provisions of this Agreement shall be preserved until satisfied.

(e) If this Agreement has not become effective pursuant to subsection 2(a) within 12 months following the date upon which Bonneville executes and delivers this Agreement to Puget, this Agreement shall be void ab initio and of no force or effect.

3. CAPACITY RIGHTS

(a) Purchase and Sale of Capacity

Pursuant to the terms and conditions of this Agreement, Puget purchases from Bonneville and Bonneville sells to Puget the Capacity Ownership Rights.

(b) **Right to Wheel for Third Parties**

No later than 30 days after the Effective Date, Puget shall notify Bonneville in writing of Puget's decision to utilize its Scheduling Share pursuant to either paragraph 3(b)(1) or paragraph 3(b)(2), and Puget shall have the right to utilize its Scheduling Share pursuant to the paragraph Puget elects. Prior to Bonneville's receipt of such notification, Puget shall utilize its Scheduling Share pursuant to paragraph 3(b)(1). If Puget fails to make an election within the prescribed time period, Puget shall be deemed to have elected the option set forth in paragraph 3(b)(1).

(1) **No Third Party Wheeling**

(A) Except as expressly provided in subparagraph 3(b)(1)(B), Puget shall not use its Scheduling Share to transmit power or energy (except for inadvertent power flows) that Puget does not own at the California-Oregon border or for which transmission Puget receives any revenue that would be reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked.

(B) If Puget's Scheduling Share is not fully utilized by Puget in any hour, Bonneville may schedule for such hour Bonneville's transactions (including, without limitation, Bonneville wheeling for other entities) and wheel such transactions over the unused portion of Puget's Scheduling Share for such hour but no longer than such hour. Puget shall be compensated for such wheeling solely by the payments as described in sections 3(b)(1)(B)(i) and (ii) below. For purposes of this subparagraph 3(b)(1)(B), Puget's Scheduling Share shall be deemed to be not fully utilized in a given hour to the extent that Puget has not scheduled, or does not schedule, on a Preschedule or Real-time Schedule basis,

any transaction for such hour on any MW amount of Puget's Scheduling Share. In return for Puget's Scheduling Share being made available to Bonneville pursuant to this subparagraph 3(b)(1)(B), Bonneville shall pay Puget

(i) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a north-to-south direction under the IS-93 rate, section II.A, or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour, and

(ii) an amount equal to the product of (1) all wheeling revenues received by Bonneville from providing short term wheeling in a south-to-north direction under the IS-93 rate, section II.A or its successor to other entities in such hour, and (2) the ratio of Puget's unused Scheduling Share in such hour to the total amount of PNW AC Intertie Operational Transfer Capability made available by Bonneville for such wheeling in such hour; provided, however, that Bonneville shall not be required to make payments for such south-to-north wheeling pursuant to this section 3(b)(1)(B)(ii) earlier than two years after the Effective Date.

Bonneville shall make payments pursuant to this subparagraph 3(b)(1)(B) in accordance with paragraph 9(f)(1).

(C) During an outage resulting from maintenance activities on the PNW AC Intertie performed by Bonneville other than maintenance activities undertaken due to emergencies or uncontrollable forces, the following shall apply:

(i) When Puget's Scheduling Share for any given hour is reduced as a consequence of such outage which reduces in Bonneville's PNW AC Intertie Operational Transfer Capability such that Puget's Scheduling Share for such hour is less than the MW amount of the aggregate of Puget's net firm transactions identified by Puget to Bonneville pursuant to section 3(b)(1)(C)(iv) for such hour, Bonneville shall, subject only to sections 3(b)(1)(C)(ii) and (iii) and to the immediately succeeding sentence, wheel on a firm basis that portion of Puget's firm transactions that equals the difference between Puget's Scheduling Share for such hour and the MW amount of the aggregate of Puget's firm transactions for such hour up to, but not in excess of, Puget's Capacity Ownership Share. Notwithstanding the foregoing, Bonneville shall only be obligated to provide such wheeling to the extent that each party with whom Puget is conducting such firm transactions has received a sufficient AC Intertie capacity allocation in California to accommodate such transactions. Puget shall pay the IS-93 rate, section II.A, or its successor for such wheeling pursuant to this section 3(b)(1)(C)(i) in accordance with subsection 9(d).

(ii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section

3(b)(1)(C)(i) if no PNW AC Intertie Operational Transfer Capability is available to Bonneville after Bonneville has scheduled all of Bonneville's Firm Schedules. For purposes of this section, "Bonneville's Firm Schedules" shall mean schedules for assured delivery or other firm transmission contracts pursuant to the Long-Term Intertie Access Policy, as revised or amended, or its successor, and schedules for Bonneville's firm power and energy sales and exchange transactions.

(iii) Bonneville shall not be obligated to provide such wheeling to Puget pursuant to section 3(b)(1)(C)(i) until Bonneville has successfully developed software to allow Bonneville to provide such wheeling to Puget or until October 1, 1994, whichever occurs sooner.

(iv) No later than ten Working Days prior to the first day of deliveries under a firm transaction, Puget shall identify such firm transaction to Bonneville. Puget shall identify such firm transaction to Bonneville by providing to Bonneville a copy of Puget's contract for such firm transaction (after information considered proprietary by Puget has been redacted by Puget). Bonneville shall review such contract to verify that the transaction is firm. If Puget and its contractor represent or state in writing that the transaction set forth in their contract is firm, Bonneville shall accept that written representation or statement as dispositive of the question of whether such transaction is firm. Implementation of such procedures in this section 3(b)(1)(C)(iv) may be varied by the

mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written.

(D) Puget retains any and all rights of access which it would otherwise have to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(2) **Third Party Wheeling**

(A) Puget may use its Scheduling Share to transmit any and all power and energy, whether or not such power or energy is owned by Puget. Puget shall have no obligation under this Agreement to make available to Bonneville any portion of Puget's Scheduling Share which is unused in any hour, and Bonneville shall not schedule over Puget's Scheduling Share without Puget's prior consent.

(B) Puget hereby waives any and all rights of access to Bonneville's PNW-PSW Intertie through the Long-Term Intertie Access Policy, as revised or amended, or its successor; provided, however, that Bonneville may, at its option, provide Puget with access to Bonneville's PNW-PSW Intertie pursuant to any provision of the Long-Term Intertie Access Policy, as revised or amended, or its successor.

(C) Puget shall provide Bonneville with the information set forth in sections 3(b)(2)(C)(i) through 3(b)(2)(C)(iii) when Puget uses its Scheduling Share to export from the Pacific Northwest energy or power received from third parties. Such exports of energy or power on a real-time basis or for durations of less than four months are excluded from this obligation. For exports of four

months or longer duration made on behalf of third parties pursuant to paragraph 3(b)(2), such information shall include:

(i) the name and business address of the third party;

(ii) the amount of power or energy and the duration of the transaction; and

(iii) the name of the recipient or purchaser of such power.

Any additional information needed by Bonneville will be obtained from such third party.

4. SCHEDULING

(a) Puget (and only Puget) shall be entitled to schedule on the PNW AC Intertie, in any hour, a MW amount up to Puget's Scheduling Share for such hour. The MW amount of Puget's Scheduling Share deemed to be scheduled on the PNW AC Intertie pursuant to this Agreement, in any hour, shall be determined as the net of Puget's north-to-south schedules and south-to-north schedules (net schedules) for such hour.

(b) Puget shall submit all schedules of its Scheduling Share on its own behalf in accordance with the procedures set forth in paragraphs 4(b)(1) and 4(b)(2). Such procedures may be varied by the mutual agreement of the Parties' Schedulers. Such mutual agreement may, but need not, be written. All hours referenced in paragraphs 4(b)(1) and 4(b)(2) are Pacific Time.

(1) Preschedules

(A) Bonneville shall make available to Puget on each Working Day as soon as practicable after 0800 hours

information regarding the PNW AC Intertie Operational Transfer Capability with respect to Preschedules. In the event an emergency or uncontrollable force causes a change in the PNW AC Intertie Operational Transfer Capability, Bonneville shall notify Puget of such change as soon as practicable.

(B) If Long-Term Intertie Access Policy Condition 1 Formula Allocation Procedures or their successor (Condition 1) are expected by Bonneville to become effective, Bonneville shall so notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 is expected to become effective. Bonneville shall notify Puget no later than 0930 hours on the Working Day prior to the day on which Condition 1 ceases to be in effect.

(C) Puget shall submit its Preschedule to the Joint Intertie Scheduling Office no later than 1000 hours on each Working Day if Condition 1 is in effect. If Condition 1 is not in effect, Puget shall submit its Preschedule to the JISO no later than 1430 hours on each Working Day.

(2) **Real-time Scheduling**

(A) Real-time Schedules shall be arranged through Bonneville's real-time scheduling office. Bonneville's real-time Scheduler shall make reasonable efforts to receive Real-time Schedules; provided, however, that Bonneville's real-time Scheduler may, but is not required to, accept Real-time Schedules between 1500 and 2200 hours on the Working Day preceding the day for which such Real-time Schedule is submitted.

(B) Real-time Schedules shall be arranged for a full hour. Arrangements shall be completed no later than 30 minutes prior to that hour.

(C) Puget shall use best efforts to keep schedule changes to a minimum; provided, however, that for purposes of this subparagraph 4(b)(2)(C), "best efforts" shall not be deemed to refer to efforts made regardless of their economic effect.

(D) The requirements set forth in subparagraphs 4(b)(2)(B) and 4(b)(2)(C) do not preclude schedule changes at other times as may be deemed necessary by any control area operators or other entities involved in effectuating such schedule changes. Such control area operators and other entities shall be notified by Bonneville of such schedule changes as soon as practicable in accordance with Prudent Utility Practice for purposes of coordinating ramps and proper accounting. Such schedule changes shall be deemed to occur at mid-ramp. The mid-ramp time and the integrated value for the hour shall be subject to the mutual agreement by such control area operators and other entities.

(E) Subject to compliance with subparagraphs 4(b)(2)(A) through 4(b)(2)(D) and with other applicable PNW AC Intertie scheduling practices then in effect, Bonneville shall make Puget's schedule change.

(c) Bonneville shall make deliveries of power or energy to the California-Oregon border or the John Day Substation, as appropriate, pursuant to schedules submitted in accordance with this section 4; provided, however, that Bonneville shall not be required to make such deliveries in an hour to the extent that Puget's schedule exceeds Puget's Scheduling Share for such hour, except as may be expressly provided pursuant to subparagraph 3(b)(1)(C).

5. **UPGRADES**

(a) Bonneville shall consult with the Committee one time each year regarding any plans for Upgrades.

(b) Prior to the completion of an Upgrade, Bonneville shall provide to Puget information in writing regarding estimated costs and the MW amount of such Upgrade, to the extent that such information is available to Bonneville.

(c) As soon as practicable following the completion of an Upgrade, Bonneville shall notify Puget in writing of the following: (1) the MW amount of such Upgrade; (2) the capital and related costs (less any amount of such costs collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, to Bonneville for completing or implementing such Upgrade; and (3) calculations of (A) Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade and (B) Puget's Capacity Ownership Percentage multiplied by the capital and related costs, if any, to Bonneville for completing or implementing such Upgrade. Puget may elect to acquire a share of such Upgrade in an amount up to Puget's Capacity Ownership Percentage multiplied by the MW amount of such Upgrade. Within 100 days from receipt of such written notice from Bonneville, Puget shall notify Bonneville in writing of Puget's decision regarding such acquisition. If Puget elects to acquire, pursuant to this subsection 5(c), a portion of such Upgrade, Puget's notice to Bonneville shall include the percentage of such Upgrade that Puget elects to acquire (Acquisition Percentage). If

Puget fails to notify Bonneville within such 100-day period, Puget shall be deemed to have elected not to acquire any of such Upgrade.

(d) If Puget elects to acquire a portion of an Upgrade pursuant to subsection 5(c), the cost to Puget shall be Puget's Acquisition Percentage multiplied by the capital and related costs for such Upgrade pursuant to the CO-94 rate and subsection 9(c) (less any amount of such cost collected by Bonneville through rates or charges other than pursuant to the CO-94 rate in Exhibit A), if any, incurred by Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(e) If Puget's Acquisition Percentage with respect to an Upgrade equals its Capacity Ownership Percentage and the Acquisition Percentage of any other Capacity Owner with respect to such Upgrade is less than its Capacity Ownership Percentage, then the following shall apply:

(1) Bonneville shall, in a timely manner, provide written notice simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage) of the MW amount equal to 100 percent of that portion of an Upgrade offered to, but not acquired by, the Capacity Owners pursuant to subsection 5(c) (Unacquired Share). If Puget and each of such other Capacity Owners have agreed in writing to an apportionment as among themselves of the Unacquired Share (Apportionment), Puget may, within 45 days following receipt of such written notice from Bonneville, by written notice request Bonneville to offer in writing to Puget such portion of the Unacquired Share as has been apportioned to Puget pursuant to the Apportionment, and Bonneville shall offer to Puget such portion of the Unacquired Share.

(2) If Bonneville does not receive from Puget and from each Capacity Owner referred to in paragraph 5(e)(1) the requests for offer pursuant to paragraph 5(e)(1) within the 45-day period

specified in such paragraph, Bonneville shall, in a timely manner, offer in writing simultaneously to Puget and to each other Capacity Owner (whose Acquisition Percentage equals its Capacity Ownership Percentage), respectively, a portion of an Upgrade offered to, but not acquired by, the other Capacity Owners pursuant to paragraph 5(e)(1) (Second Unacquired Share) up to the "Additional Share Offered" determined as follows:

Additional Share Offered = $(A + B) \times C$

where: A = Puget's Capacity Ownership Percentage.

B = Percentage equal to the sum of Capacity Ownership Percentages of Capacity Owners that acquired respectively an Acquisition Percentage equal to their Capacity Ownership Percentage.

C = Second Unacquired Share.

(3) Within 30 days following Puget's receipt of Bonneville's written offer pursuant to paragraph 5(e)(2), Puget shall notify Bonneville in writing of Puget's decision regarding acquisition of the Additional Share Offered. If Puget fails to notify Bonneville within such 30-day period, Puget shall be deemed to have elected not to acquire any of the Additional Share Offered. If Puget elects pursuant to this paragraph 5(e)(3) to acquire any or all of the Additional Share Offered, then:

(A) Puget shall include in its notice to Bonneville pursuant to this paragraph 5(e)(3) such share (Additional Share Acquired) of the Additional Share Offered as Puget elects to acquire pursuant to this paragraph 5(e)(3), and

(B) the cost to Puget with respect to such acquisition shall be equal to the proportion of the Additional Share Acquired to such Upgrade multiplied by the capital and related costs for such Upgrade pursuant to the CO-94

rate and subsection 9(c) (less any amount of such costs collected by Bonneville through charges other than payments by Puget pursuant to subsection 5(d) or subparagraph 5(e)(3)(B)), if any, to Bonneville for completing or implementing such Upgrade. Puget shall pay such costs pursuant to such payment terms as may be mutually agreed to in writing by the Parties.

(f) All capacity offered but not acquired pursuant to subsections 5(c) and (e) shall for purposes of this Agreement remain with Bonneville.

(g) After Puget has either accepted or declined all offers of capacity by Bonneville pursuant to subsections 5(c) and (e), Puget's Capacity Ownership Share, Capacity Ownership Percentage, and Scheduling Percentage in Exhibit C shall be revised to reflect changes resulting from Puget's elections pursuant to subsections 5(c) and (e). Revision of Exhibit C shall be pursuant to subsection 19(d). Exhibit G shall be revised accordingly pursuant to subsection 19(i).

6. SALE OR ASSIGNMENT

(a) This Agreement or any interest herein shall not be transferred, sold, alienated, or assigned by Puget to any person without Bonneville's prior and express written consent. Such consent shall not be unreasonably withheld. In determining whether to grant its consent under this subsection 6(a), Bonneville shall take into consideration information including, but not limited to, whether the person or entity to whom this Agreement or any interest therein is proposed to be transferred, sold, alienated, or assigned is a person or entity entitled to request and receive transmission services pursuant to section 211 of the Federal Power Act, whether such person or entity can either provide its own scheduling services or has contracted with another entity to provide such scheduling services, whether such person or entity has the financial capability to meet the payment obligations under this Agreement, and whether the person or entity is either electrically interconnected to Bonneville's transmission system or has

contractual arrangements for wheeling with others who are electrically interconnected to Bonneville's transmission system. This Agreement shall inure to the benefit of and be binding upon the Parties, their respective legal representatives, permitted assigns, and successors in interest. Any transfer, sale, alienation, or assignment made by Puget in violation of this section 6 shall be void ab initio and without any force or effect whatsoever.

(b) Bonneville hereby consents to the transfer, sale, alienation, or assignment by Puget to any other Capacity Owner of all or part of its Capacity Ownership Share and all of Puget's rights and obligations pursuant to this Agreement with respect thereto. Bonneville hereby further consents to the transfer, sale, alienation, or assignment by Puget of the entire Agreement and of all of Puget's rights and obligations under this Agreement to a Scheduling Utility.

(c) Bonneville hereby consents to the assignment by Puget of this Agreement or of any of Puget's rights under this Agreement as security for any indebtedness, whether present or future, of Puget pursuant to any mortgage, trust, security agreement or similar instrument of indebtedness (each such instrument, a Debt Instrument) made by and between Puget and any mortgagee, trustee, secured party or holder of such instrument of indebtedness, respectively; provided, however, that if Puget has defaulted in the performance of its obligations under any Debt Instrument, such that the mortgagee, trustee, secured party or holder of such Debt Instrument, as the case may be, would be entitled at that time to accelerate the amount of indebtedness under such Debt Instrument, Puget shall give Bonneville prompt written notice in reasonable detail of such default and shall, at Bonneville's election, enter into good faith discussions with Bonneville regarding the cure of such default.

(d) If Puget transfers, sells, alienates, or assigns, with Bonneville's consent, all or any portion of this Agreement and any rights and obligations pursuant to this Agreement to any person or party, Puget shall give Bonneville written notice of such transfer, sale, alienation,

or assignment within 10 days after the execution and delivery of the agreement effectuating such transaction by all parties to such transaction.

7. OPERATION, MAINTENANCE, AND MANAGEMENT

(a) Pursuant to the terms and conditions of the Northwest Intertie Agreements, Bonneville is the operator of the PNW AC Intertie. As such, Bonneville is responsible for the dispatch of the PNW AC Intertie in accordance with Prudent Utility Practice. Bonneville's duties as operator of the PNW AC Intertie shall include, but are not limited to, consistent with Prudent Utility Practice and Northwest Intertie Agreements: (1) determining the PNW AC Intertie Operational Transfer Capability; (2) implementing and assisting in rectifying emergency outages on the PNW AC Intertie due to system emergencies or uncontrollable forces; (3) implementing maintenance outages; and (4) giving and receiving switching orders on the PNW AC Intertie. In making any determination or in taking any other action referred to in the immediately preceding sentence, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing. Bonneville shall operate, maintain, and manage Bonneville's PNW AC Intertie, and study, plan, and implement Upgrades, consistent with Prudent Utility Practice.

(b) Bonneville shall determine and revise as necessary the PNW AC Intertie Rated Transfer Capability consistent with Prudent Utility Practice and engineering studies based on then existing reliability criteria developed by the North American Electric Reliability Council, the Western Systems Coordinating Council, the Northwest Power Pool, and Bonneville. In the event the PNW AC Intertie Rated Transfer Capability is changed, Bonneville shall promptly notify Puget in writing of such change and the new PNW AC Intertie Rated Transfer Capability. If and to the extent that the reliability criteria for determining the PNW AC Intertie Rated Transfer Capability

change substantially, Bonneville shall notify Puget in writing of such change.

(c) If at any time during the Term, Bonneville's PNW AC Intertie Rated Transfer Capability becomes less than 3450 MW, or if at any time during the Term there is an imminent likelihood that Bonneville's PNW AC Intertie Rated Transfer Capability would become less than 3450 MW, then Bonneville shall reinforce the Federal Columbia River Transmission System so as to raise Bonneville's PNW AC Intertie Rated Transfer Capability to 3450 MW or otherwise to prevent Bonneville's PNW AC Intertie Rated Transfer Capability from becoming less than 3450 MW. Puget's Capacity Ownership Share shall not be decreased on account of any failure by Bonneville to reinforce the Federal Columbia River Transmission System pursuant to this subsection 7(c).

(d) In the event that Bonneville implements a Reinforcement pursuant to subsection 7(c), Bonneville shall equitably allocate the Reinforcement Cost for such Reinforcement between Bonneville and Puget based on factors including, but not limited to, load responsibility, contractual obligation and generation integration responsibility. Any equitable allocation or agreed to allocation (pursuant to the immediately succeeding sentence) of a Reinforcement Cost pursuant to this subsection 7(d) shall be reflected as a Reinforcement Cost in an Operating Plan proposed by Bonneville pursuant to section 13. To the extent that Bonneville and Puget have agreed in writing to an allocation of a Reinforcement Cost incurred by Bonneville pursuant to an agreement or modification referred to in subsection 8(b), the Reinforcement Cost so allocated shall not be subject to arbitration pursuant to section 14 or section 15. Any Reinforcement Cost not allocated to Puget pursuant to this subsection 7(d) shall not be payable by Puget pursuant to this Agreement.

(e) Bonneville shall provide Puget notice of maintenance outages in accordance with the accepted standards for notice on the PNW AC Intertie. Such notice shall include an evaluation of the impact on

Puget's Scheduling Share. In scheduling or planning maintenance on PNW AC Intertie, Bonneville shall give fair consideration to Puget's interests to the extent such interests have been expressed to Bonneville in writing.

8. EXISTING AGREEMENTS

(a) Bonneville shall use good faith efforts to maintain in effect the Interconnection Agreement or its successor.

(b) Bonneville shall use its best efforts to maintain Puget's rights under this Agreement (i) by making no modification to the Northwest Intertie Agreements, (ii) by not entering into any other agreement with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie, and (iii) by making no modification to the agreements referred to in the immediately preceding clause (ii) that would have a substantial negative impact on Puget's rights pursuant to sections 3, 4, 7, or to subsection 9(b), 9(c), or 11(a) without Puget's prior written consent. Without limiting, modifying, or otherwise affecting any of its rights pursuant to sections 9, 13, 14, 15, and 16, Puget hereby consents to Bonneville's modification of the Northwest Intertie Agreements or Bonneville's entering into other agreements or modification to such Agreements with respect to the ownership, operation, maintenance, or management of the PNW AC Intertie to the extent that such modification or such agreement is made or entered into by Bonneville for the purpose of performing Bonneville's obligations pursuant to subsection 7(c).

9. PAYMENT PROVISIONS

As full compensation for their respective payment obligations under this Agreement, Puget shall make payments to Bonneville in accordance with the provisions of this section 9, and Bonneville shall make payments and refunds to Puget in accordance with the provisions of this section 9.

(a) **Lump Sum Payment**

(1) As soon as practicable after the Effective Date, Bonneville shall render a bill to Puget for the Initial Lump Sum Payment (less the negotiation deposit, if any, with applicable interest as described in section C of Exhibit D) and such bill shall include as an attachment and as part of such bill a completed section C of Exhibit D, setting forth the calculation of such Initial Lump Sum Payment due Bonneville in accordance with section IV.A of the CO-94 rate set forth in Exhibit A. Puget shall make such payment pursuant to the CO-94 rate and the applicable GTRSPs set forth in Exhibit A. Each of Bonneville and Puget agrees that section C of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(2) **Calculation and Billing of the Adjusted Capacity Ownership Price**

(A) Approximately December 1995, or as soon as practicable thereafter, Bonneville shall, in accordance with section IV.B of the CO-94 rate set forth in Exhibit A, calculate the Adjusted Capacity Ownership Price to reflect actual construction costs of the facilities listed in section A of Exhibit D and the actual AFUDC with respect to such facilities. Such calculation shall be made in accordance with column 2, section B of Exhibit D.

(B) Promptly after Bonneville has calculated the Adjusted Capacity Ownership Price pursuant to subparagraph 9(a)(2)(A), Bonneville shall render a bill or refund voucher to Puget, and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2), section B of Exhibit D (with a completed column 2), and a completed section D of Exhibit D reflecting the Adjusted Lump Sum Payment. If the

Adjusted Lump Sum Payment is greater than the Initial Lump Sum Payment, Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to which the Parties may mutually agree, the amount set forth in such bill, which amount shall be equal to the amount set forth on line 7, section D of Exhibit D (such amount including interest as set forth on line 6, section D of Exhibit D). If the Adjusted Lump Sum Payment is less than the Initial Lump Sum Payment, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in such refund voucher, which amount shall be equal to the amount set forth on line 7, section D, of Exhibit D (such amount including interest as set forth on line 6, section D, of Exhibit D). Each of Bonneville and Puget agrees that sections A, B, and D of Exhibit D are consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(3) **Calculation and Billing of the Revised Adjusted Capacity Ownership Price**

(A) After payment is made by Puget pursuant to subparagraph 9(a)(2)(B), or a refund is made by Bonneville to Puget pursuant to subparagraph 9(a)(2)(B), Bonneville may, in accordance with the CO-94 rate set forth in Exhibit A, make one or more adjustments to the Adjusted Capacity Ownership Price; provided, that any such adjustment shall be made by Bonneville within 30 days after the date on which (i) Bonneville receives, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp or any other entity performing work for Bonneville on the Third AC Intertie Project, payment from Transmission Agency of Northern California,

PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, or (ii) Bonneville pays, pursuant to any audit with respect to the Third AC Intertie Project by Bonneville, Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project, any amount to Transmission Agency of Northern California, PacifiCorp, or any other entity performing work for Bonneville on the Third AC Intertie Project; and provided, further, that no adjustment of the Adjusted Capacity Ownership Price or of any Revised Adjusted Capacity Ownership Price shall be made by Bonneville after December 31, 2005.

(B) Promptly after Bonneville has calculated a Revised Adjusted Capacity Ownership Price, Bonneville shall render to Puget a bill or refund voucher with respect to such Revised Adjusted Capacity Ownership Price and such bill or refund voucher shall include as an attachment and as part of such bill or refund voucher section A of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), section B of Exhibit D (with a completed column 2 and a completed column with respect to each Revised Adjusted Capacity Ownership Price), and a completed section E of Exhibit D reflecting the current Revised Adjusted Capacity Ownership Price and the current Revised Adjusted Lump Sum Payment. If the current Revised Adjusted Lump Sum Payment with respect to such Revised Adjusted Capacity Ownership Price is greater than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, then Puget shall pay to Bonneville, within 45 days from the date of such bill or within such other time period to

which the Parties may mutually agree, the amount set forth in the bill referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E, of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E, of Exhibit D). If the current Revised Adjusted Lump Sum Payment is less than the Adjusted Lump Sum Payment or the immediately preceding Revised Adjusted Lump Sum Payment, as the case may be, Bonneville shall pay to Puget, within 30 days after the date of such refund voucher, the amount set forth in the refund voucher referred to in this subparagraph 9(a)(3)(B), which amount shall be equal to the amount set forth on line 7, section E of Exhibit D with respect to the current Revised Adjusted Lump Sum Payment (such amount including interest as set forth on line 6, section E of Exhibit D). Each of Bonneville and Puget agrees that section E of Exhibit D is consistent with the CO-94 rate set forth in Exhibit A on the Effective Date.

(4) For purposes of implementing the CO-94 rate, the following shall apply:

(A) the calculations pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the adjustment "to reflect the difference between the actual and the estimated Capacity Ownership Price" required under section IV.B of the CO-94 rate;

(B) the calculations of interest pursuant to footnote 2 of section D of Exhibit D and footnote 2 of section E of Exhibit D shall be deemed to be the computation of "interest using the weighted average interest rate on Bonneville's outstanding bonds" required pursuant to section IV.B of the CO-94 rate;

(C) the calculations of the Adjusted Capacity Ownership Price and of the Revised Adjusted Capacity Ownership Price pursuant to paragraphs 9(a)(2) and 9(a)(3) shall be deemed to be the determination of the "actual Capacity Ownership Price" required pursuant to section IV.B of the CO-94 rate;

(D) as used in the CO-94 rate, the terms "Bonneville's PNW AC Intertie," "PNW AC Intertie," "Third AC Intertie," "Third AC Intertie Project," and "Third AC Intertie System Reinforcement" shall be deemed to have the respective meanings of such terms set forth in section 1;

(E) as used in the CO-94 rate, the term "Capacity Ownership Share" shall be deemed to mean "Capacity Ownership Percentage" as defined in section 1;

(F) the indirect costs and overhead costs described in footnote 5 of section B of Exhibit D shall be deemed to be the indirect costs and overhead costs referred to in section III.A of the CO-94 rate; and

(G) the last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

> The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(5) For purposes of application of the CO-94 rate set forth in Exhibit A, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(A) section I;

(B) section III.A;

(C) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(D) subsection 4 of section IV.A;

(E) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A; and

(F) for purposes of subsection 16(e) of this Agreement and as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(b) **Annual Charges**

(1) **Payments Pursuant to AC-93 Rate**

(A) From and after the first Working Day after Bonneville receives payment from Puget pursuant to paragraph 9(a)(1), Bonneville shall bill Puget on the monthly power bill in accordance with the AC-93 rate set forth in Exhibit A. Puget shall pay such bill in accordance with the applicable GTRSPs set forth in Exhibit A.

(B) For purposes of application of the AC-93 rate, no provision of the General Transmission Rate Schedule Provisions set forth in Exhibit A, other than the following provisions of the General Transmission Rate Schedule Provisions set forth in Exhibit A (or their successors in substance), shall have any application or effect with respect to this Agreement:

(i) section I;

(ii) section III.A;

(iii) the last three sentences of section IV.A, without regard to subsections 1, 2, 3, 4, 5, 6 and 7 of such section IV.A;

(iv) the first sentence of subsection 3 of section IV.A;

(v) subsection 4 of section IV.A;

(vi) the first paragraph and the first sentence of the second paragraph of subsection 5 of section IV.A;

(vii) the first paragraph of subsection 6 of section IV.A; and

(viii) as deemed necessary by Bonneville to correct mathematical and computational errors on bills, subsection 7 of section IV.A.

(C) The last paragraph of section I.B of the General Transmission Rate Schedule Provisions set forth in Exhibit A shall be deemed to read in its entirety as follows:

The meaning of terms used in the transmission rate schedules shall be as defined in the Agreement or in provisions which are attached to the Agreement or, if not defined therein, such terms shall be as defined in any of the above Acts.

(D) Bonneville hereby agrees that the provisions of the AC-93 rate shall have no application or effect with respect to the following:

(i) any replacement of the series capacitor banks containing polychlorinated biphenyl at the Sand Springs, Sycan and Fort Rock Substations; and

(ii) any replacement commenced prior to the Effective Date or not completed prior to September 30, 1995.

(E) Upon and after the effective date of the annual costs rate set forth in Exhibit B, Bonneville shall cease billing Puget pursuant to the AC-93 rate.

(2) **Payments Pursuant to Annual Costs Rate**

From and after the date the annual costs rate set forth in Exhibit B becomes effective, the following shall apply:

(A) **Operations Costs, Maintenance Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs**

(i) During each fiscal year during the Term, Bonneville shall bill Puget on the monthly power bill, and Puget shall pay, pursuant to Exhibit B,

forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for such fiscal year. Such costs shall be, respectively, the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the fiscal year in which such month occurs.

(ii) Within eight months after the end of each fiscal year during the Term (such fiscal year being hereinafter referred to as a "Fiscal Year"), Bonneville shall determine and calculate, pursuant to Exhibit I, Schedules A, B, D, E, F, G, and H, actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year most recently ended.

(iii) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs for the Fiscal Year is greater than the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End

of Term Costs for the Fiscal Year, Bonneville shall refund to Puget the difference between such forecast costs and such actual costs as a lump sum payment, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Bonneville shall, promptly following the date on which the calculation of such difference is made, provide Puget written notice of such refund. Within the 30-day period referred to in the first sentence of this section 9(b)(2)(A)(iii), Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(iv) If, based on the calculation performed pursuant to subparagraph 9(b)(2)(A)(ii), the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is equal to or less than 105 percent, but greater than 100 percent, of the sum of the forecast Operations costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and

Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs in the Operating Plan for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions. Within the 30-day period referred to in the immediately preceding sentence, Bonneville shall provide to Puget an amended Operating Plan containing revised schedules in the format set forth in Exhibit I, Schedules A, B, D, E, F, G, and H, respectively, with a completed last column reflecting the difference between actual and forecast Operations Costs, actual and forecast Maintenance Costs, General Plant Costs, actual and forecast Other Costs, actual and forecast Contracts and Rates Costs, actual and forecast Power Scheduling Costs, and actual and forecast End of Term Costs for the Fiscal Year.

(v) If, based on the calculation performed pursuant to section 9(b)(2)(A)(ii), the sum of the actual Operations Cost, actual Maintenance Cost, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs for the Fiscal Year is greater than 105 percent of the sum of the forecast Operations Cost, forecast Maintenance Cost, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast

End of Term Costs for the Fiscal Year, Bonneville shall bill to Puget on the monthly power bill the difference between such actual costs and such forecast costs as a lump sum charge, with interest pursuant to section 9(b)(2)(A)(vi), within 30 days after the date on which the calculation referred to in section 9(b)(2)(A)(ii) is made. Puget shall pay such bill in accordance with the Billing Provisions; provided, however, that Bonneville shall not bill Puget pursuant to this section 9(b)(2)(A)(v) any amount which exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year unless and until such amount which exceeds 100 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in the Operating Plan for the Fiscal Year has been included in an Operating Plan amended pursuant to subsection 13(k).

(vi) Simple interest shall be accrued on payments or refunds due pursuant to this paragraph 9(b)(2) with respect to any fiscal year during the Term using the weighted average interest rate on Bonneville's outstanding bonds or other debt instruments then used by Bonneville and such interest shall accrue from (and including) the date of the last day of such fiscal year to (but

excluding) the date of refund to Puget or to (but excluding) the due date of a payment due Bonneville.

(B) **Replacement Cost and Reinforcement Cost**

Bonneville shall bill Puget on the monthly power bill Replacement Costs for any Replacement and Reinforcement Costs for any Reinforcement. Bonneville shall render such bill within 15 months following the date on which the project work order for such Replacement or such Reinforcement, as the case may be, is closed. Puget shall pay such bill pursuant to Exhibit B and sections 9(b)(2)(B)(i), 9(b)(2)(B)(ii), 9(b)(2)(B)(iii) and 9(b)(2)(B)(iv).

(i) If the forecast Replacement Cost for a Replacement is greater than the actual Replacement Cost for such Replacement or if the forecast Reinforcement Cost for a Reinforcement is greater than the actual Reinforcement Cost for such Reinforcement, Bonneville shall bill Puget the actual Replacement Cost for such Replacement or the actual Reinforcement Cost for such Reinforcement, as the case may be. Bonneville shall provide to Puget an Operating Plan amended in accordance with subsection 13(k) containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement, as the case may be.

(ii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual

Reinforcement Cost is equal to or less than 105 percent, but greater than 100 percent, of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B). Bonneville shall provide to Puget an amended Operating Plan containing a revised schedule in the format set forth in Exhibit I, Schedule C, reflecting the difference between the actual and forecast Replacement Cost for such Replacement or the actual and forecast Reinforcement Cost for such Reinforcement.

(iii) If, for each Replacement or Reinforcement, the actual Replacement Cost or actual Reinforcement Cost is greater than 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, Bonneville shall bill Puget such actual Replacement Cost or such actual Reinforcement Cost, as the case may be, on the monthly power bill and Puget shall pay such bill pursuant to subparagraph 9(b)(2)(B); provided, however, that Bonneville shall not bill Puget pursuant to this subparagraph 9(b)(2)(B) any amount which exceeds 105 percent of the forecast Replacement Cost or forecast Reinforcement Cost, as the case may be, unless and until such amount which exceeds 100 percent of such forecast Replacement or such forecast Reinforcement Cost, as the case may be, has been included in an amended Operating Plan pursuant to subsection 13(k).

(iv) Charges pursuant to sections 9(b)(2)(B)(i), (ii) and (iii) for Replacement Costs and Reinforcement Costs shall accrue simple interest pursuant to section III.D of Exhibit I.

(c) **Upgrade Charges**

For purposes of implementing the CO-94 rate, the following shall apply:

(1) as used in the CO-94 rate, the term "upgrade" shall be deemed to mean "Upgrade" as defined in section 1, the term "rated transfer capability" shall be deemed to mean "PNW AC Intertie Rated Transfer Capability" as defined in section 1 and the term "AFUDC" shall be deemed to have the meaning set forth for such term in section 1;

(2) the "Capacity Ownership Share of the capital and related cost of the upgrade," referred to in section III.B of the CO-94 rate shall be deemed to be the costs pursuant to subsection 5(d) and subparagraph 5(e)(3)(B), as applicable; and

(3) "construction costs (including direct, indirect and overhead costs) and AFUDC" referred to in section III.B of the CO-94 rate and "related costs" referred to in section III.B of the CO-94 rate together shall be deemed to be Upgrade costs and shall be determined in the same manner in which Replacement Costs are determined pursuant to section III of Exhibit I; provided, however, that expenses that are properly allocable to an Upgrade (i.e., "related costs" referred to in section III.B of the CO-94 rate) in accordance with generally accepted accounting principles (as defined in Exhibit I) may be included by Bonneville in Upgrade costs for such Upgrade.

(d) **Payments of Charges Pursuant to Section 3(b)(1)(C)(i)**

Bonneville shall bill Puget for wheeling provided pursuant to section 3(b)(1)(C)(i) on Puget's monthly power bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A and Puget shall pay such bill in accordance with the IS-93 rate, section II.A, or its successor, set forth in Exhibit A; provided, however, that under any successor to the IS-93 rate, Puget shall not be obligated to pay any rate or charge greater than the rate or charge payable by any other party to which Bonneville provides nonfirm wheeling services on Bonneville's PNW AC Intertie for such party's nonfirm transaction of a duration similar to Puget's wheeling transaction pursuant to section 3(b)(1)(C)(i).

(e) **Suspension for Failure to Perform**

(1) If at any time during the term of this Agreement Bonneville does not receive payment due and owing to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d), Bonneville shall be entitled to suspend performance of its obligations to Puget pursuant to section 4 without incurring any liability to Puget therefor; provided, that Bonneville shall not be entitled to suspend performance pursuant to this paragraph 9(e)(1) earlier than five Working Days following receipt from Bonneville by Puget of written notice of such suspension. Such suspension shall continue in effect until the next Working Day following the Working Day on which Puget makes payment in full to Bonneville of the balance owed to Bonneville pursuant to paragraph 9(a)(2) or 9(a)(3) or to subsection 9(b) or 9(d). During the period of such suspension, Puget shall not be entitled to participate through the Committee in any review of an Operating Plan commenced by the Committee pursuant to section 13 during such period of suspension, or to participate in any arbitration commenced by the Committee pursuant to sections 14 and 15 during such period of suspension, or to participate in any audit commenced

by the Committee pursuant to section 16 during such period of suspension.

(2) If during any period in any month Bonneville fails to make deliveries in accordance with subsection 4(c), Puget shall be entitled, without incurring any liability to Bonneville therefor, to delay any payment due and owing to Bonneville by Puget pursuant to subsection 9(b) or 9(d) for a period, equal to the period during which Bonneville failed to make such deliveries, commencing on the date the monthly power bill for such month would otherwise be payable by Puget pursuant to this Agreement; provided, however that Puget's entitlement pursuant to this paragraph 9(e)(2) shall apply only with respect to the amount of such monthly power bill to be paid directly to Bonneville or its agent.

(f) **Payments or Refunds by Bonneville**

(1) Bonneville shall make any payment to Puget pursuant to subparagraph 3(b)(1)(B) within 30 days following the end of the month in which such payment becomes due to Puget pursuant to subparagraph 3(b)(1)(B).

(2) Bonneville shall pay to Puget, in a lump sum, any refund due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2) within 30 days following the date on which such refund becomes due to Puget pursuant to subsection 16(e) or paragraph 16(f)(2), respectively.

(3) Bonneville shall pay any refund, credit, or payment due to Puget under section 18 pursuant to the terms and conditions set forth in section 18.

(4) Each payment, credit or refund due to Puget by Bonneville pursuant to this Agreement shall be made by Bonneville, at Bonneville's option, (A) by check payable to the order of Puget,

(B) by electronic funds transfer of immediately available funds into such account as may be designated in writing by Puget from time to time for such purpose or (C) by crediting the amount of such payment, credit or refund on Puget's power bill.

10. TRANSMISSION LOSSES

(a) To compensate Bonneville for transmission losses incurred by Bonneville in making deliveries scheduled by Puget pursuant to this Agreement, Puget shall make available, or arrange to have made available, to Bonneville, at any point mutually acceptable to the Parties at which the respective electric systems of Puget and Bonneville are interconnected, on the corresponding hour 168 hours later or on another hour to be agreed upon, the amounts of electric power equal to Puget's net PNW AC Intertie schedule multiplied by the appropriate loss factor specified in Exhibit E. Puget's net PNW AC Intertie schedule shall be, for any given hour, the absolute value of the sum of Puget's north-to-south schedules (positive) and south-to-north schedules (negative) for such hour.

(b) Upon the conclusion of any review by Bonneville of the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan provided to the Committee pursuant to section 13. The Committee may make recommendations regarding such results and any revisions to the loss factor in Exhibit E, Part A. Only recommendations regarding assumptions (including, without limitation, data inputs and source of date) made by Bonneville in its review or revision of the loss factor in Exhibit E, Part A, and recommendations regarding the results of such review or revision shall be subject to arbitration pursuant to section 14.

(c) Puget's Scheduling Share shall not be reduced by any amount of losses returned to Bonneville pursuant to subsection 10(a).

11. REMEDIAL ACTIONS

(a) Bonneville's Responsibilities

(1) Within five days after the Effective Date, Bonneville shall notify Puget in writing of the plan for remedial actions required to maintain the PNW AC Intertie Rated Transfer Capability, which plan shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice. If and to the extent that such plan is amended, modified, or replaced, Bonneville shall, promptly following such amendment, modification, or replacement, provide written notice to Puget of such amendment, modification, or replacement, as the case may be. Bonneville shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, required to maintain the portion of Bonneville's PNW AC Intertie Rated Transfer Capability not purchased by Capacity Owners. Such remedial actions shall be consistent with Western System Coordinating Council standards and Prudent Utility Practice.

(2) Bonneville shall be responsible for generating appropriate control signals for transmission to Puget for purposes of effectuating remedial actions pursuant to this section.

(b) Puget's Responsibilities

(1) Puget shall be responsible for providing a capability to arm and having available appropriate remedial actions, which may include generator dropping, load tripping, or other remedial actions required to maintain Puget's Capacity Ownership Share. Such remedial actions shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1) and Prudent Utility Practice. Bonneville

may perform engineering analyses to confirm Puget's providing capability to arm and having available appropriate remedial actions pursuant to this paragraph 11(b)(1).

(2) In any given hour, Puget shall be responsible for providing sufficient remedial actions, which may include generator dropping, load tripping, or other acceptable remedial actions, to maintain Puget's schedule on the PNW AC Intertie for such hour. To the extent that load tripping or generator dropping is required as a remedial action by Puget pursuant to this paragraph 11(b)(2) in any given hour, the required amount of such load tripping or such generator dropping shall be determined by dividing the amount of power scheduled by Puget on Puget's Scheduling Share in such hour by the total amount of power scheduled on the PNW AC Intertie in such hour and multiplying the result by the total amount of generation or load (in MW) to be armed for the PNW AC Intertie in such hour.

(3) Puget shall provide, design, operate, and maintain the necessary equipment to accept control signals from Bonneville and to transmit such signals to Puget's generator dropping, load tripping, or other remedial action sites, and to arm and initiate the appropriate control action(s). Such design, operation, and maintenance shall be consistent with Western System Coordinating Council standards, the plan referred to in paragraph 11(a)(1), and Prudent Utility Practice.

(4) Puget and Bonneville may mutually agree that Bonneville will, pursuant to terms and conditions mutually acceptable to the Parties, provide the remedial actions required of Puget pursuant to subsection 11(b).

12. CAPACITY OWNERS' COMMITTEE

(a) Composition of Committee

Puget may appoint one representative (and an alternate who may act in the absence of such representative) as a member of the Capacity Owners' Committee (Committee). If during any period Puget fails to appoint a representative to the Committee, Puget waives any and all rights during such period that would otherwise have accrued to it, individually or as a member of the Committee, pursuant to sections 12, 13, 14, 15, and 16 of this Agreement. Puget hereby appoints as its representative pursuant to this subsection the following representative and alternate to the Committee:

Representative: Vice President Power Planning

Alternate: Manager Power Contracts

(b) Convening Meetings

(1) Any Capacity Owner that has appointed a representative to the Committee may convene a meeting of the Committee pursuant to the procedures set forth in subsection 12(e). The Capacity Owner convening a Committee meeting shall be responsible for preparing any necessary notices, identifying the subject matter and issues to be discussed, and transmitting notices and relevant documents to the other Committee members and, if appropriate, to Bonneville.

(2) At the written request of any Capacity Owner that has appointed a representative to the Committee, Bonneville shall attend Committee meetings.

(3) The Committee may conduct business only at a properly convened meeting at which a quorum, as defined in subsection 12(c), is present. The Committee shall make or convey any

request, designation, recommendation, notice, appointment, submission, audit report or exception, or statement to which Bonneville is required to respond or which creates or triggers an obligation of Bonneville, pursuant to this Agreement, only upon a decision of the Committee made at a properly convened meeting at which a quorum is present.

(4) Each fiscal year, Bonneville shall convene an annual meeting of the Committee. The purpose of such annual meeting shall be to discuss the Operating Plan delivered, pursuant to subsection 13(b), to each Capacity Owner that has appointed a representative to the Committee. Bonneville shall convene such annual meeting no earlier than 15 days, but no later than 30 days, following the date of such delivery of the Operating Plan.

(5) In addition to the meeting referred to in paragraph 12(b)(4), Bonneville may, at its discretion, convene meetings of the Committee, pursuant to the procedures set forth in subsection 12(e), to present to the Committee any information Bonneville deems relevant.

(c) **Meeting Quorum**

The respective representatives of all of the Capacity Owners that have appointed a representative to the Committee, less one, shall constitute a quorum.

(d) **Meetings by Telephone Conference**

Committee meetings pursuant to the Capacity Ownership Agreements may be conducted by telephone provided all Capacity Owners and, if appropriate, Bonneville, are notified pursuant to the procedures set forth in subsection 12(e) of any such meeting.

(e) **Meeting Notices**

(1) All Committee meeting notices pursuant to the Capacity Ownership Agreements shall be provided in writing no less than 14 days prior to such meeting.

(2) Any Committee meeting notice required by this section shall be deemed properly made if delivered in person, by electronic facsimile, or by mail or other qualified delivery service, postage prepaid, to the person specified below:

If to Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232
Telephone (503) 230-5152
Facsimile (503) 230-5207

If to Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515
Telephone (206) 462-3137
Facsimile (206) 462-3175

If to Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101
Telephone (206) 386-4530
Facsimile (206) 386-4955

If to PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232
Telephone (503) 288-1234
Facsimile (503) 288-2334

If to Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201
Telephone (206) 258-8211
Facsimile (206) 258-8305

If to Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411
Telephone (206) 502-8294
Facsimile (206) 502-8628

Attendance at a meeting by a representative of a Capacity Owner constitutes waiver by such Capacity Owner of notice of such meeting.

(3) Either Party may, by written notice to the other Party and to the Capacity Owners other than Puget, change the designation, address, or facsimile number of the person so specified by it in subsection 12(a) or paragraph 12(e)(2).

13. **OPERATING PLAN AND AMENDMENTS TO THE OPERATING PLAN**

(a) The provisions of this section shall become effective commencing August 1, 1995; provided, however, that unless and until the annual costs rate set forth in Exhibit B is approved by FERC on an interim basis, Bonneville shall not have any right pursuant to this Agreement to bill or charge to Puget, and Puget shall not have any obligation pursuant to this Agreement to pay to Bonneville, any amount pursuant to any Operating Plan.

(b) **Delivery of Operating Plan**

(1) On or before August 1, 1995, Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1996 and an Operating Plan for Bonneville's PNW AC Intertie for fiscal year 1997.

(2) Not later than one year preceding the first day of each fiscal year, other than the fiscal years specified in paragraph 13(b)(1), Bonneville shall deliver to each Capacity Owner that has appointed a representative to the Committee an Operating Plan for Bonneville's PNW AC Intertie for such fiscal year.

(c) Each Operating Plan delivered pursuant to subsection 13(b) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast costs for the fiscal year to which such Operating Plan pertains, and such Operating Plan may contain such other information as Bonneville may deem relevant; and each amendment of an Operating Plan delivered pursuant to subsection 13(k) shall contain the following information for Bonneville's PNW AC Intertie with respect to forecast or actual costs, as appropriate, for the fiscal year to which such Operating Plan pertains, and such amendment may contain such other information as Bonneville may deem relevant:

(1) a forecast of, or the actual, Allocated Direct Cost of Operations Cost (pursuant to section I.C of Exhibit I), Indirect Cost of Operations Cost (pursuant to section I.D of Exhibit I), and Overhead Cost of Operations Cost (pursuant to section I.E of Exhibit I) in the format set forth in Exhibit I, Schedule A;

(2) a forecast of, or the actual, Direct Cost of Maintenance Cost (pursuant to section II.B of Exhibit I), Indirect Cost of Maintenance Cost (pursuant to section II.D of Exhibit I), and Overhead Cost of Maintenance Cost (pursuant to section II.E of Exhibit I) in the format set forth in Exhibit I, Schedule B;

(3) a forecast of, or the actual, Direct Cost of Replacements and Reinforcements (pursuant to section III.A of Exhibit I), Indirect Cost and Overhead Cost of Replacements and Reinforcements (pursuant to section III.B of Exhibit I), and AFUDC of Replacements and Reinforcements (pursuant to section III.C of Exhibit I) in the format set forth in Exhibit I, Schedule C, for each Reinforcement and Replacement which is expected to be, in the fiscal year to which the Operating Plan pertains, a planned new start, construction work in progress on a previously initiated Reinforcement or Replacement, as the case may be, or a closed work order. The forecast shall include for each such Reinforcement or Replacement an estimate of the total cost of construction and the cost to be incurred with respect to such Reinforcement or Replacement during each fiscal year until the work order for such Reinforcement or Replacement has been closed. Bonneville may elect, but shall not be required, to include in any such forecast the information set forth in the immediately preceding sentence regarding any Replacement and Reinforcement which is expected to be planned a new start in any fiscal year following the fiscal year to which the Operating Plan pertains. In the event Bonneville elects to forecast Direct Cost, Indirect Cost, and Overhead Cost of any Reinforcement or Replacement which is expected to be a

planned new start in any fiscal year subsequent to the fiscal year to which the Operating Plan pertains, Bonneville shall provide to the Committee such forecast costs, in the format set forth in Exhibit I, Schedule C (together with additional information pertinent to such forecast costs as required by paragraph 13(c)(9)), 30 days prior to the date such Operating Plan is delivered to the Committee pursuant to subsection 13(b). In addition, Bonneville shall include such forecast costs in the Operating Plan delivered to the Committee pursuant to subsection 13(b);

(4) the General Plant Cost (pursuant to section IV of Exhibit I) in the format set forth in Exhibit I, Schedule D;

(5) a forecast of, or the actual, Other Costs (pursuant to section V of Exhibit I) in the format set forth in Exhibit I, Schedule E;

(6) a forecast of, or the actual, Contracts and Rates Costs (pursuant to section VI of Exhibit I) in the format set forth in Exhibit I, Schedule F;

(7) a forecast of, or the actual, Power Scheduling Costs (pursuant to section VII of Exhibit I) in the format set forth in Exhibit I, Schedule G;

(8) a forecast of, or the actual, End of Term Costs (pursuant to section VIII of Exhibit I) in the format set forth in Exhibit I, Schedule H. Such forecast shall include Bonneville's proposed apportionment of such End of Term Costs among Puget and Capacity Owners other than Puget and Bonneville's rationale for such apportionment;

(9) additional information pertinent to the forecast costs, actual costs, and General Plant Cost provided pursuant to paragraphs 13(c)(1) through 13(c)(8), including, without limitation, descriptions of the activities or projects and explanations of the

costs comprising the Direct Cost components of such forecast costs, actual costs, and General Plant Cost, and explanations of MFU counts; and

(10) if Bonneville has reviewed the loss factor in Exhibit E, Part A, pursuant to subsection 19(f), the Operating Plan shall contain the results of such review, including any revision to the loss factor in Exhibit E, Part A, pursuant to subsection 10(b), and any additional information pertinent to such review.

(d) **Requests by Committee**

(1) No later than 15 days after the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), the Committee may make a single request of Bonneville in writing for:

(A) such supporting documentation, data, and information as may be reasonably necessary to analyze (i) the Operating Plan, or its constituent parts, delivered to the Committee pursuant to subsection 13(b), or (ii) any amendment to an Operating Plan pursuant to subsection 13(k); and

(B) such documentation, data, and information relating to Bonneville's present or past activities or practices concerning Bonneville's PNW AC Intertie and to alternatives considered by Bonneville to costs or activities described in the Operating Plan or any amendment to an Operating Plan as may be reasonably necessary for the Committee to formulate recommendations pursuant to subsection 13(e);

provided, however, that with regard to requests for documentation, data, and information pursuant to this paragraph 13(d)(1), the Committee must designate in such

request the specific item in the Operating Plan or in any amendment to an Operating Plan to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information. Such single request may contain multiple parts.

(2) The Committee shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to paragraph 13(d)(1).

(3) Bonneville shall have 20 days from the date it receives any request pursuant to paragraph 13(d)(1) to provide the documentation, data, and information requested; provided, however, that Bonneville shall be under no obligation (A) to create additional documentation, data, or information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Committee, or (D) to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or any regulation and Executive Order applicable to Bonneville.

(4) The Committee in such request shall designate one of its members to be its representative for the sole purpose of receiving such documentation, data, or information from Bonneville pursuant to this subsection 13(d). Bonneville shall deliver such documentation, data, or information to the representative designated by the Committee to receive such materials.

(5) For purposes of this subsection 13(d) and subsection 13(f), each of Bonneville and the Committee shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests for, documentation, data, and information and responses to such requests.

(e) The Committee shall have 20 days from the date on which it receives documentation, data, or information from Bonneville pursuant to subsection 13(d) or, if none was requested, 50 days from the date on which the annual meeting was convened pursuant to paragraph 12(b)(4), whichever date is later, to recommend to Bonneville in writing a revision or revisions to any forecast cost or General Plant Cost in the Operating Plan. The Committee shall have the time periods set forth in subsection 13(m) to recommend to Bonneville in writing a revision or revisions to a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan. Such recommendation shall set forth, at a minimum, the exact revisions to the forecast cost or General Plant Cost proposed by the Committee and the reasons for such revisions. Failure of the Committee to recommend a revision or revisions to all or any portion of a forecast cost or General Plant Cost in the Operating Plan or a forecast cost or actual cost or General Plant Cost in any amendment to an Operating Plan within the applicable time limit set forth above shall be deemed to constitute acceptance by the Committee of all portions of the forecast costs and General Plant Cost of the Operating Plan for which the Committee has not recommended a revision.

(f) No later than 15 days after receipt of a Committee recommendation made pursuant to subsection 13(e), Bonneville may make a single request (which may contain multiple parts) in writing of the Committee for such supporting documentation, data, and information as may be reasonably necessary to analyze the Committee's recommendation, including without limitation, any estimated costs or forecast costs contained in such recommendation; provided, however, that the Capacity Owners that have appointed a representative to the Committee shall be under no obligation (1) to create additional

documentation, data, or information, (2) to provide documentation, data, or information that is not readily available to the Committee or to any Capacity Owner that has appointed a member to the Committee, (3) to provide to Bonneville documentation, data, or information that the Committee has previously provided to Bonneville; provided, further, that with regard to requests for documentation, data, and information pursuant to this subsection 13(f), (1) Bonneville must designate in such request the specific item in the Committee's recommendation to which such requested documentation, data, or information is directly related and explain the need for such documentation, data, or information, and (2) Bonneville shall use reasonable efforts, consistent with Bonneville's needs as set forth in this subsection 13(f), to minimize and limit the scope and number of parts of the request for documentation, data, and information made pursuant to this subsection. Such single request shall be made of the Committee by delivering a copy of the request to each Capacity Owner that has appointed a representative to the Committee. The Committee shall have 20 days from the date of its receipt of Bonneville's request to provide a single response containing the documentation, data, and information requested.

(g) If the Committee makes any recommendation in writing pursuant to subsection 13(e), Bonneville shall have the greater of 15 days from the date of receipt of the requested documentation, data, and information requested pursuant to subsection 13(f) or, if none was requested, 30 days from the date of receipt of the Committee's recommendations made pursuant to subsection 13(e) to, by written notice to each Capacity Owner that has appointed a representative to the Committee, accept the recommendation, accept the recommendation in part, reject the recommendation, or propose an action that is responsive to the Committee's recommendation and that is different from Bonneville's proposal contained in the Operating Plan. If Bonneville makes such a proposal, Bonneville shall set forth in such written notice the exact revisions to the Operating Plan. The Committee shall have 7 days from the date of receipt of Bonneville's proposal to make any requests in writing for supporting

documentation, data, and information as set forth in subsection 13(d). Bonneville shall have 7 days to respond to those requests as set forth in subsection 13(d). Failure of Bonneville to respond in writing to any recommendation of the Committee within the applicable time period set forth in this subsection 13(g) shall be deemed to constitute rejection of such recommendation.

(h) If Bonneville rejects all or any portion of the Committee's recommendation, or if the Committee elects not to accept a proposal made by Bonneville pursuant to subsection 13(g), then the Committee may

(1) elect by written notice to Bonneville to refer to binding arbitration, pursuant to section 14 and consistent with subsections 13(i) and 14(b), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g); and

(2) elect by written notice to Bonneville to refer to nonbinding arbitration pursuant to section 15 and consistent with subsections 15(a) and 15(d), that portion of such recommendation of the Committee not accepted by Bonneville or that portion of a recommendation of the Committee to which Bonneville responded with a proposal pursuant to subsection 13(g).

Failure of the Committee to elect to refer to arbitration

(A) such portion of any recommendation of the Committee not accepted by Bonneville within 15 days following Bonneville's rejection or acceptance in part of such recommendation of the Committee pursuant to subsection 13(g), or

(B) any proposal made by Bonneville pursuant to subsection 13(g) within 15 days following Bonneville's written notice of such proposal or, if documentation, data, or information was requested by the Committee pursuant to subsection 13(g), within 15 days following receipt by the Committee of such documentation, data, or information pursuant to subsection 13(g),

shall be deemed to constitute acceptance by the Committee of Bonneville's rejection or acceptance in part of the recommendation of the Committee or of Bonneville's proposal and waiver by the Committee of any right pursuant to this section 13 or to section 15 to arbitrate such recommendation or portion thereof.

(i) The Committee may, subject to the immediately succeeding sentence, arbitrate, pursuant to subsection 13(h), any recommendation by the Committee concerning a revision pursuant to this Agreement to a loss factor set forth in any Operating Plan or in any amendment to an Operating Plan or concerning any forecast cost or actual (allocated or otherwise) cost set forth in any Operating Plan or in any amendment to an Operating Plan (including the following costs and related items set forth in any Operating Plan, or in any amendment to an Operating Plan, pursuant to Exhibit I, Schedule A, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13; Exhibit I, Schedule B, lines 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15; Exhibit I, Schedule C, lines 1, 2, 3, 4 and 5; Exhibit I, Schedule D, lines 3, 4, 5, 6, 7, 8, 9, 10 and 11; Exhibit I, Schedule E, lines 2 and 3; Exhibit I, Schedule F, lines 1, 2, 3, 4, 5, 6, 7, 8, and 9; Exhibit I, Schedule G, lines 1, 2, 3, 4, 5, 6 7, 8, and 9; and Exhibit I, Schedule H, lines 1, 2, 3, and 4). The Committee's right pursuant to this subsection 13(i) to arbitrate any such recommendation shall be subject to the following limitations:

(1) if such recommendation, or portion thereof, includes a Replacement Cost for a Replacement or a Reinforcement Cost for a Reinforcement, and such Replacement Cost or Reinforcement Cost was included in a previous Operating Plan

(either of such costs, a Previous Operating Plan Cost), the Committee may arbitrate pursuant to this subsection 13(i) such recommendation, or portion thereof, only to the extent that such recommendation, or portion thereof, includes any Replacement Cost or Reinforcement Cost in excess of the Previous Operating Plan Cost;

(2) the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, pertaining to a revision to a loss factor pursuant to this Agreement only to the extent such arbitration is permitted by subsection 10(b);

(3) the Committee may arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning an Other Cost only to the extent that such Other Cost is a cost set forth in an Operating Plan or amendment to an Operating Plan pursuant to Exhibit I, Schedule E, line 2 and such recommendation, or portion thereof pertains to whether such Other Cost is properly allocated to Bonneville's PNW AC Intertie pursuant to Exhibit I, section V;

(4) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs, and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operations Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs, and forecast End of Term Costs set forth in such Operating Plan or in any amendment to an Operating Plan, the Committee may arbitrate pursuant to this subsection 13(i) any such recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan only to the extent that such actual cost exceeds 105 percent of the forecast cost for such activity or such project; provided, however, that, without limiting any of Puget's rights

and benefits pursuant to subsection 16(c), the Committee may not arbitrate pursuant to this subsection 13(i) any recommendation, or portion thereof, concerning any actual cost for any activity or project described in such Operating Plan or in any amendment to an Operating Plan if such actual cost is less than 105 percent of the forecast for such activity or such project;

(5) the Committee may not arbitrate, pursuant to this subsection 13(i), (a) the allocation by Bonneville pursuant to this Agreement of any of its costs to overall overhead costs or to overall indirect costs, or (b) the allocation by Bonneville pursuant to this Agreement of a portion of Bonneville's overall overhead costs and overall indirect costs to its total system operations costs, its total system maintenance costs, its total capital costs or its total indirect and overhead power scheduling costs; provided, however, that nothing in this paragraph (5) shall be deemed to prevent or restrict the Committee from arbitrating pursuant to this subsection 13(i) the level (rather than the allocation) of any of Bonneville's Exhibit I, Schedule A, line 9 total system operations indirect costs and line 11 total system operations overhead costs; Bonneville's Exhibit I, Schedule B, line 11 total system maintenance indirect costs and line 13 total system maintenance overhead costs; Bonneville's total capital costs; Bonneville's Exhibit I, Schedule F, line 6 total indirect contracts and rates costs and Bonneville's Exhibit I, Schedule F, line 7 total overhead contracts and rates costs; or Bonneville's Exhibit I, Schedule G, line 6 total indirect power scheduling costs and Bonneville's Exhibit I, Schedule G, line 7 total overhead power scheduling costs;

(6) the Committee may not arbitrate any recommendation, or any portion thereof, regarding any amendment to an Operating Plan made pursuant to sections 9(b)(2)(A)(iv) and 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2);

(7) the Committee may not arbitrate any such recommendation, or portion thereof, to the extent that in doing so the arbitrators would be required to decide a matter of law in order to render a decision pursuant to subsection 14(h). If, subsequent to the Effective Date, Bonneville is given legal authority to submit to binding arbitration matters of law, Bonneville shall enter into good faith negotiations with Puget and Capacity Owners other than Puget regarding a revision to this paragraph 13(i)(7) enabling arbitration of matters of law pursuant to this subsection 13(i) consistent with such legal authority; and

(8) the Committee may not arbitrate any recommendation, or portion thereof, regarding an allocation of a Reinforcement Cost to the extent prohibited by subsection 7(d).

In arbitrating any recommendation, or portion thereof, pursuant to this subsection 13(i), the Committee may raise in support of such recommendation arguments regarding whether any forecast or actual cost should be based upon activities different in degree, but not in kind, from the activities upon which such forecast or actual cost in the Operating Plan is based.

(j) Each Operating Plan provided pursuant to subsection 13(b) which has completed the Committee review process set forth in subsections 13(d) through 13(g) shall take effect on the first day of the fiscal year to which such Operating Plan pertains and shall remain in effect for the duration of such fiscal year.

(k) At any time during the fiscal year in which an Operating Plan is in effect, or within 8 months after the end of such fiscal year, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast or actual Operations Cost, Maintenance Cost, General Plant Cost, Other Cost, Contracts and Rates Cost, Power Scheduling Cost, or End of Term Cost in such Operating Plan. At any time during the fiscal year an Operating Plan

is in effect, or within 30 months after a work order for a Replacement or Reinforcement is closed, Bonneville may amend such Operating Plan, pursuant to subsections 13(l) through 13(n), to reflect a different forecast cost or actual cost component for such Replacement or Reinforcement.

(l) Any amendment made to any Operating Plan pursuant to subsection 13(k) shall be provided by delivery of a copy in writing of such amendment by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(m) Consideration of amendments to the Operating Plan pursuant to subsection 13(l) shall be consistent with the procedures set forth above in subsections 13(c) through 13(k), except that the time limits set forth in such subsections shall be reduced as follows: 15 days shall be 7 days, 20 days shall be 10 days, 30 days shall be 15 days, and 50 days shall be 25 days. For purposes of computing the time limits in this subsection 13(m), the date Bonneville provides the Capacity Owners with a proposed amendment, pursuant to subsection 13(k), shall be deemed to be the date the annual meeting was convened for purposes of paragraph 13(d)(1) and subsection 13(e).

(n) Without limiting any of Puget's rights and benefits pursuant to subsection 13(i) and sections 14 and 15, any Operating Plan amended pursuant to section 9(b)(2)(A)(v) or 9(b)(2)(B)(iii), or subsection 13(k) shall take effect when such amendment is accepted by the Committee pursuant to subsection 13(e) or 13(h). Any Operating Plan amended pursuant to section 9(b)(2)(A)(iii), 9(b)(2)(A)(iv), 9(b)(2)(B)(i), or 9(b)(2)(B)(ii), or subsection 14(j), 16(e), or paragraph 16(f)(2) shall take effect as soon as such amendment is delivered by Bonneville to each Capacity Owner that has appointed a representative to the Committee.

(o) An Operating Plan shall, during the fiscal year in which such Operating Plan is in effect, establish the costs which Puget is obligated to pay pursuant to the terms and conditions of this

Agreement. In no event shall such Operating Plan, or any portion thereof, contain or constitute an obligation of Bonneville to undertake, or to expend funds on, activities described or indicated in such Operating Plan.

14. ARBITRATION

(a) During any arbitration process conducted pursuant to this section 14, Puget shall act through the Committee. Each of Bonneville and Puget agrees to be bound by any decision rendered by the arbitrators in any arbitration brought pursuant to subsection 13(i) and this section 14.

(b) The Committee may initiate arbitration pursuant to subsection 13(i) by taking the following actions:

(1) an affirmative vote to initiate arbitration by at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(2) either of the following:

(a) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to subsection 13(i) within the applicable time period established in subsection 13(h); or

(b) giving written notice to Bonneville of the Committee's decision to initiate arbitration within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subsection 14(b) shall set forth in detail the matter or matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(c) Bonneville shall, within 10 Working Days after receipt of the notice by the Committee referred to in subsection 14(b), appoint a second arbitrator and provide by written notice to each Capacity Owner that has appointed a representative to the Committee the name, street address and telephone number of the arbitrator appointed by Bonneville. The two arbitrators appointed by the Committee and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville.

(1) If the arbitrators appointed by the Committee and by Bonneville, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by Bonneville, then within 30 days after the date of the appointment of an arbitrator by Bonneville, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(2) If Bonneville fails to appoint an arbitrator within 15 days after receipt of the notice by the Committee referred to in subsection 14(b), then within 30 days after the date of such notice, the Committee may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(3) If, pursuant to either paragraph 14(c)(1) or 14(c)(2), the Committee applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Committee shall give Bonneville written notice of such application within 5 days after the date of filing such application.

(d) The three arbitrators appointed pursuant to subsections 14(b) and 14(c) shall select by a majority vote an alternative pursuant to subsection 14(g).

(e) Within 10 days after the appointment of a third arbitrator pursuant to subsection 14(c), the arbitrators shall establish a schedule for submission of written positions by Bonneville and Puget, respectively. The arbitrators must establish a schedule for such submissions pursuant to this subsection 14(e) that will allow the arbitration to be concluded, and the decision of the arbitrators rendered pursuant to subsection 14(g), within 120 days following the date of the appointment of the third arbitrator. A copy of any submission by the Committee to the arbitrators pursuant to this section 14 shall be simultaneously served by the Committee on Bonneville, and a copy of any submission by Bonneville to the arbitrators pursuant to this section 14 shall be simultaneously served by Bonneville on each Capacity Owner that has appointed a representative to the Committee. The Committee shall state, in a letter to the arbitrators, as its proposed alternative to each Bonneville proposal in dispute, the recommendation proposed by the Committee pursuant to subsection 13(g) and rejected in whole or in part by Bonneville pursuant to subsection 13(g). Bonneville shall state its position and proposed resolution of the dispute in a letter to the arbitrators. If Bonneville made a proposal in response to such recommendation of the Committee pursuant to subsection 13(g), then such position and proposed resolution shall set forth such proposal, or if Bonneville made no such proposal, then such position and proposed resolution shall set forth the relevant portion of the Operating Plan. If, however, the arbitration concerns an exception pursuant to paragraph 16(f)(3), then the positions and proposed resolutions of Bonneville and the Committee shall be as established pursuant to such subsection. The Committee may then submit a response to Bonneville's letter, and Bonneville may thereafter submit a reply to the Committee's response. Bonneville and the Committee shall have an equal number of days to prepare and serve their replies.

(f) No submission by either the Committee or Bonneville to the arbitrators pursuant to subsection 14(e) shall be more than 50 pages in length (not including exhibits). If requested in writing by either the

Committee or Bonneville, and for good cause shown, the arbitrators may permit any submission by such Party to exceed 50 pages.

(g) The arbitrators shall select, as between the Committee's recommendation pursuant to subsection 13(e), on the one hand, and the portion of Bonneville's proposed Operating Plan to which the Committee's recommendation pertains or Bonneville's proposal pursuant to subsection 13(g) not accepted by the Committee, on the other, the alternative which

(1) is consistent with the provisions of this Agreement and

(2) (A) in conformity with the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto, would better achieve the desired result consistent with safety, reliability, and cost-benefit or (B) if there are no such generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area, would, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, be reasonably expected to better achieve the desired result consistent with safety, reliability, and cost-benefit.

(h) In applying the standards set forth in subsection 14(g), the arbitrators shall take into consideration, among other things (a) that Bonneville and Puget each have responsibilities for service to customers within and without the Pacific Northwest region in accordance with applicable law, (b) that Bonneville and others jointly own the PNW AC Intertie and Bonneville owes contractual obligations to those parties regarding the PNW AC Intertie, (c) that Bonneville must operate, as a practical matter, the PNW AC Intertie in coordination with the operation of the interconnected intertie facilities in California, and (d) that the PNW AC Intertie is a major import-export facility important to the service of loads in and out of the region.

(i) In any arbitration pursuant to this section 14, the arbitrators shall choose, pursuant to subsection 14(g), only between the alternatives proposed by Bonneville and the Committee and shall have no authority to resolve such arbitration other than by selecting an alternative proposed by either Bonneville or the Committee.

(j) Upon selection by the arbitrators of an alternative pursuant to subsection 14(g), then Bonneville shall amend the Operating Plan to cause it to conform to the decision of the arbitrators.

(k) If the arbitrators have not made a selection of an alternative pursuant to subsection 14(i) before the date on which the Operating Plan becomes effective pursuant to subsection 13(j), then Puget shall make payments of annual charges pursuant to such Operating Plan. If the arbitrators subsequently select the Committee's alternative, then Bonneville shall, subsequent to amending such Operating Plan pursuant to subsection 14(j), refund to or bill Puget its pro rata share of the amount of the incremental difference between the costs set forth in such Operating Plan as amended pursuant to subsection 14(j) and 105 percent of the costs set forth in such Operating Plan, prior to its amendment pursuant to subsection 14(j), to the extent that such costs were incurred during the period from the first day of effectiveness of such Operating Plan pursuant to subsection 13(j) to the date of the arbitrators' decision, such refund to be made pursuant to subsection 9(f) and such payment to be made pursuant to subsection 9(b).

(l) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 14 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay its own expenses related to the arbitration proceeding including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(m) Any judgment rendered by a court of competent jurisdiction upon an award made by the arbitrators pursuant to this section 14 may be entered in any court having jurisdiction thereof.

15. NONBINDING ARBITRATION

(a) The Initiating Party (as defined in paragraph 15(e)(1)) may, subject to the immediately succeeding sentence, elect by written notice to Responding Party (as defined in paragraph 15(e)(1)) to refer to nonbinding arbitration pursuant to the other provisions of this section 15 the following: (i) if the Initiating Party is the Committee, any recommendation by the Committee, or any portion thereof, concerning any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 and (ii) any other issue, dispute, or controversy regarding the Parties' respective rights and obligations pursuant to this Agreement. The Initiating Party's right pursuant to this subsection 15(a) to arbitrate any recommendation or any issue, dispute or controversy shall be subject to the following limitations:

(1) the Initiating Party may not arbitrate pursuant to this subsection 15(a): (A) any recommendation with respect to an Operating Plan or any amendment to an Operating Plan or (B) any issue, dispute, or controversy, which recommendation, issue, dispute or controversy may be arbitrated pursuant to subsection 13(i) or 16(f);

(2) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation not permitted to be arbitrated pursuant to paragraphs 13(i)(1), 13(i)(3), 13(i)(4), and 13(i)(8);

(3) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or

controversy concerning a loss factor or revision to a loss factor set forth in Exhibit E, Part A or Part B pursuant to this Agreement;

(4) the Committee may not (but the Puget or Bonneville may) arbitrate pursuant to this subsection 15(a) any recommendation, issue, dispute, or controversy concerning any right or obligation of Puget pursuant to this Agreement that is not a right or obligation, as the case may be, of each other Capacity Owner under its respective Capacity Ownership Agreement; or

(5) if the sum of the actual Operations Costs, actual Maintenance Costs, General Plant Costs, actual Other Costs, actual Contracts and Rates Costs, actual Power Scheduling Costs and actual End of Term Costs in any Operating Plan exceeds 105 percent of the sum of the forecast Operating Costs, forecast Maintenance Costs, General Plant Costs, forecast Other Costs, forecast Contracts and Rates Costs, forecast Power Scheduling Costs and forecast End of Term Costs set forth in such Operating Plan, the Committee may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 only to the extent that such actual cost exceeds 105 percent of the forecast for such activity or such project; provided, however, that, without limiting any of Puget's rights and benefits pursuant to section 16(f), no Initiating Party may arbitrate pursuant to this subsection 15(a) any recommendation, or portion thereof, concerning any actual cost for any activity or project set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B,

lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7 if such actual cost is less than 105 percent of the forecast for such activity or such project; and

(6) the Initiating Party may not arbitrate pursuant to this subsection 15(a) any issue, dispute, or controversy (A) concerning matters of ratemaking (for purposes of this subsection 15(a), the term "ratemaking" shall mean the determination of matters appropriately determined pursuant to section 7(i) of the Regional Act, including (i) Bonneville's revenue requirements (including without limitation Bonneville's depreciation and repayment standards and planned net revenues for risk, but excluding program level issues determined in the Federal budget process), (ii) Bonneville's cost of service analysis (including functionalization, segmentation, and allocation of costs contained in such analysis, but excluding any allocation of costs contemplated in Exhibit I), (iii) Bonneville's rate design, and (iv) any related environmental analysis of proposed rates; (B) concerning a final action of Bonneville, which final action is not itself performance of any obligation of Bonneville or Bonneville's Administrator under this Agreement; or (C) concerning, or requiring the decision of, a matter not arising under this Agreement or the other Capacity Ownership Agreements.

(b) Except as otherwise provided in paragraph 15(a)(4), all arbitrations pursuant to this section 15 shall be between Bonneville and the Committee.

(c) A copy of any submission (including, without limitation, any statement of position or any brief) by the Initiating Party or the Responding Party to the arbitrators pursuant to this section 15 shall be simultaneously served by such party on the Responding Party or Initiating Party, respectively. No submission by either the Initiating

Party or the Responding Party to the arbitrators shall be more than 50 pages in length (not including exhibits). If requested in writing by either the Initiating Party or the Responding Party, and for good cause shown, the arbitrators may permit any submission by such party to exceed 50 pages.

(d) With respect to any arbitration pursuant to this section 15 of any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) Only the Committee may initiate arbitration with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7. The Committee may initiate nonbinding arbitration pursuant to this section 15 by taking the following actions:

(A) an affirmative vote to initiate arbitration pursuant to this section 15 by the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one; and

(B) either of the following:

(i) giving written notice to Bonneville of the Committee's decision to initiate arbitration pursuant to this section 15 within the applicable time period set forth in subsection 13(h); or

(ii) giving written notice to Bonneville of the Committee's decision to initiate arbitration

within 20 days after the date on which Bonneville notifies in writing each Capacity Owner that has appointed a representative to the Committee of Bonneville's disagreement with any exception pursuant to subsection 16(f).

The notice referred to in this subparagraph 15(d)(1)(B) shall (x) indicate that such vote has been taken and (y) set forth in detail the matters to be arbitrated and the name, street address and telephone number of the arbitrator appointed by the Committee.

(2) The respective rights and obligations of the Committee and of Bonneville with respect to arbitration pursuant to this subsection 15(d), unless otherwise provided in this subsection 15(d), shall be as set forth in subsections 14(d) through 14(l).

(e) With respect to any arbitration pursuant to this section 15 of any issue, dispute, or controversy other than with respect to any forecast cost or actual cost set forth in any Operating Plan or in any amendment to an Operating Plan pursuant to Exhibit I, Schedule A, lines 9 and 11; Exhibit I, Schedule B, lines 11 and 13; Exhibit I, Schedule D, lines 1 and 2; Exhibit I, Schedule F, lines 6 and 7; and Exhibit I, Schedule G, lines 6 and 7, the following shall apply:

(1) The party (which term, for purposes of this subsection 15(e), shall refer to Bonneville, on the one hand, and to the Committee or Puget, on the other) initiating arbitration (Initiating Party) shall initiate arbitration pursuant to this section 15 by serving written notice on the other party (Responding Party) of its initiation of arbitration. If the Committee is the party initiating arbitration, the Committee, in addition to serving such notice, shall initiate such arbitration by an affirmative vote to do so of at least the respective representatives of all of the Capacity Owners that have appointed representatives to the Committee, less one.

The Committee shall indicate that such vote has been taken in such notice to Bonneville. Any such notice by an Initiating Party shall set forth in detail the following: (A) the issue, dispute, or controversy to be arbitrated and the Initiating Party's position regarding such issue, dispute, or controversy; (B) the relief sought by the Initiating Party; and (C) the name, street address, and telephone number of the arbitrator appointed by the Initiating Party. The Responding Party shall, within 15 days after receipt of the notice by the Initiating Party referred to in this subsection 15(e), appoint a second arbitrator and provide written notice to the Initiating Party and to the arbitrator appointed by the Initiating Party of the name, street address and telephone number of the arbitrator appointed by the Responding Party. The arbitrators appointed by the Initiating Party and by Bonneville, respectively, shall appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party.

(A) If the arbitrators appointed by the Initiating Party and by the Responding Party, respectively, fail to appoint a third arbitrator within 15 days after the date of the appointment of an arbitrator by the Responding Party, then within 30 days after the date of the appointment of an arbitrator by the Responding Party the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of a third arbitrator.

(B) If the Responding Party fails to appoint an arbitrator within 15 days after receipt of the notice by the Initiating Party referred to in paragraph 15(e)(1), then within 30 days after the date of such notice the Initiating Party may apply to the Chief Judge of the United States District Court for the District of Oregon for appointment of two arbitrators.

(C) If, pursuant to either subparagraph 15(e)(1)(A) or 15(e)(1)(B), the Initiating Party applies to the Chief Judge of the United States District Court for the District of Oregon for appointment of one or more arbitrators, then the Initiating Party shall give the Responding Party written notice of such application within one day after the date of filing such application.

(2) The three arbitrators appointed pursuant to paragraph 15(e)(1) shall decide any issue, dispute, or controversy by majority vote.

(3) Within 20 days after the appointment of a third arbitrator pursuant to paragraph 15(e)(1) with respect to any arbitration pursuant to this subsection 15(e), the arbitrators shall establish a schedule for the completion of such arbitration. The first day pursuant to such schedule shall be hereafter referred to in this subsection 15(e) as the "Arbitration Commencement Date."

(4) No later than 15 days after the Arbitration Commencement Date, the Initiating Party may make a single request in writing to the Responding Party for documentation, data, and information relevant to or reasonably necessary to support the Initiating Party's position communicated to the Responding Party pursuant to paragraph 15(e)(1). Such single request may contain multiple parts. The Initiating Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data, and information pursuant to this paragraph.

(5) The Responding Party shall have 20 days from the date it receives the request from the Initiating Party pursuant to paragraph 15(e)(4) to provide the documentation, data, and information requested; provided, however, that the Responding Party shall be under no obligation pursuant to this paragraph 15(e)(5) (A) to create additional documentation, data, or

information, (B) to provide documentation, data, or information that is not readily available to it, (C) to provide to the Committee documentation, data, or information that Bonneville has previously provided to the Initiating Party or (D) if Bonneville is the Responding Party, to provide documentation, data, or information that Bonneville would not otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Reform Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(6) No later than 15 days after the Arbitration Commencement Date, the Responding Party may make a single request in writing to the Initiating Party for documentation, data and information relevant to Initiating Party's position communicated to the Responding Party pursuant to subsection 15(e)(4). Such single request may contain multiple parts. The Responding Party shall use reasonable efforts to minimize and limit the scope and number of parts of the request for documentation, data and information pursuant to this paragraph.

(7) The Initiating Party shall have 20 days from the date it receives the request from the Responding Party pursuant to paragraph 15(e)(6) to provide the documentation, data and information requested; provided, however, that the Initiating Party shall be under no obligation pursuant to this paragraph 15(e)(7) (A) to create additional documentation, data, or information, (B) to provide documentation, data or information that is not readily available to it, (C) to provide to the Responding Party documentation, data, or information that the Initiating Party has previously provided to the Responding Party or (D) if Bonneville is the Initiating Party, to provide documentation, data, or information that Bonneville would not

otherwise be required to provide or that would otherwise be exempted from disclosure pursuant to the Freedom of Information Act, 5 U.S.C. section 552 (including, without limitation, the Freedom of Information Act of 1986), as amended or superseded, or pursuant to any regulation and Executive Order applicable to Bonneville.

(8) For purposes of this subsection 15(e), each of the Initiating Party and the Responding Party shall cooperate and use reasonable efforts to, in a timely manner, resolve disputes regarding, and clarify requests by it for, documentation, data, and information and responses to such requests.

(9) Within 65 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may state in reasonable detail its position regarding any issue, dispute or controversy to be arbitrated pursuant to this subsection 15(e) in a letter to the arbitrators and to the other party to the arbitration of such issue, dispute, or controversy Within 85 days following the Arbitration Commencement Date, each of the Initiating Party and the Responding Party may submit a letter to the arbitrators and to the other party responding to the letter that the other submitted to the arbitrators pursuant to the immediately preceding sentence.

(10) The arbitrators shall resolve any issue, dispute, or controversy pursuant to this subsection 15(e) by deciding (taking into consideration, among other things, any letter submitted by the Initiating Party or the Responding Party with respect to such issue, dispute, or controversy) whether the position of the Initiating Party or the position of the Responding Party regarding the action taken or proposed to be taken by the Responding Party conforms more closely with the standard for such action set forth in this Agreement. The arbitrators shall have no authority to fashion a resolution of such arbitration other than pursuant to this paragraph 15(e)(10).

(f) Any selection by the arbitrators of an alternative pursuant to subsection 15(d) and any decision by the arbitrators pursuant to subsection 15(e) shall be reported by the Initiating Party to the Bonneville Administrator (Administrator) for review within 30 days after such selection or decision is made. The Administrator shall either accept or reject in writing such selection or decision. If the Administrator fails to either accept or reject such selection or decision, as the case may be, within 90 days after such selection or decision is made, such selection or decision, as the case may be, shall be deemed to be accepted by the Administrator.

(g) If the Administrator accepts any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e), such selection or decision shall become binding upon Puget and Bonneville at the time of its acceptance.

(h) The Administrator may reject any selection by the arbitrators of an alternative pursuant to subsection 15(d) or any decision by the arbitrators pursuant to subsection 15(e) only for one or more of the following reasons:

(1) the arbitrators did not follow the arbitration procedures set forth in this section 15;

(2) the arbitrators decided a matter that is not a matter arising under this Agreement as set forth in paragraph 15(a)(6);

(3) the arbitrators did not completely apply the appropriate standard for arbitration pursuant to this section 15;

(4) the arbitrators granted relief in contravention of this Agreement;

(5) the arbitrators' decision is not supported by substantial, competent evidence; or

(6) implementation of the arbitrators' decision would cause Bonneville to violate a statutory obligation of Bonneville's or would cause Bonneville to breach a contractual obligation not in contravention of this Agreement.

(i) Bonneville shall be responsible to pay a fraction of the costs for the services and expenses of the arbitrators pursuant to this section 15 equal to 1 ÷ (n + 1), where "n" equals the number of Capacity Owners. The Committee shall be responsible to pay the balance of the costs for the services and expenses of the arbitrators. Each of Bonneville and the Committee shall pay for its own expenses related to the arbitration proceeding, including, without limitation, attorney fees, costs incurred in development and preparation of documents, staff costs, and compensation for consultants.

(j) If the Initiating Party elects to arbitrate any issue, dispute, or controversy pursuant to this section 15, the Initiating Party must initiate arbitration of such issue, dispute, or controversy within one year following the occurrence of the event giving rise to such issue, dispute, or controversy. Failure of the Initiating Party to initiate arbitration of any such issue, dispute, or controversy within such one-year period shall constitute a waiver of the Initiating Party's right to arbitrate such issue, dispute, or controversy pursuant to this section 15.

16. AUDIT RIGHTS

(a) The Committee shall have the right to perform an audit of Bonneville's books, records, and documents used in or relating to the determination of the Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to the Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months

after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(2)(B).

(b) The Committee shall have the right to perform an audit of Bonneville's books, records and documents used in or relating to the determination of any Revised Adjusted Capacity Ownership Price, or used in or relating to any billing or refund with respect to any Revised Adjusted Capacity Ownership Price. Such audit shall be performed within 24 months after the date of Bonneville's bill or refund voucher rendered by Bonneville pursuant to subparagraph 9(a)(3)(B).

(c) The Committee shall have the right to audit Bonneville's books, records, and documents (i) used in or relating to the determination of any charge (including, without limitation, any MFU count made pursuant to section I.A of Exhibit I) billed to Puget pursuant to paragraph 9(b)(2) and subsection 9(c), or (ii) used in or relating to any billing or refund with respect to any such charge. Such audit shall be performed within 36 months after the date of Bonneville's bill or refund voucher for such charge rendered by Bonneville to Puget pursuant to paragraph 9(b)(2) or subsection 9(c), as the case may be.

(d) Bonneville shall not be responsible to pay any of the expenses incurred by any of the Capacity Owners in performing any audit pursuant to this section 16. Bonneville shall not directly charge Puget or any Capacity Owner other than Puget for Bonneville's costs incurred by Bonneville with respect to any audit pursuant to this section 16 unless Bonneville develops a general practice of charging, through direct charges, each of its customers for such costs incurred by Bonneville in connection with audits undertaken pursuant to those customers' respective contracts with Bonneville.

(e) After completing any audit specified above, the Committee shall promptly provide to Bonneville a written report of the results of such audit. If such audit report includes any exception taken as a result of such audit and Bonneville agrees with such exception, Bonneville

shall, within 30 days following Bonneville's receipt of such audit report and consistent with such audit exception,

(1) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to paragraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(2) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and either (A) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (B) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this subsection 16(e) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such audit report is received by Bonneville to (but excluding) the date on which such amount is refunded to Puget.

(f) If an audit report provided to Bonneville by Puget pursuant to subsection 16(e) includes any exception taken as a result of such audit and Bonneville does not agree with such exception, then the following shall apply:

(1) Bonneville may, within 30 days following its receipt of such audit report, propose to the Committee a resolution of any

inconsistency noted in any exception taken as a result of such audit;

(2) If the Committee accepts such resolution proposed by Bonneville, then Bonneville shall, within 30 days following Bonneville's receipt of such audit report and consistent with such resolution,

(A) if such exception is with respect to the Adjusted Lump Sum Payment or to any Revised Adjusted Lump Sum Payment, render to Puget a revised bill or refund voucher pursuant to subparagraph 9(a)(2)(B) or 9(a)(3)(B), respectively, with respect to such Adjusted Lump Sum Payment or such Revised Adjusted Lump Sum Payment, and

(B) if such exception is with respect to an Operating Plan, amend the Operating Plan to which such exception pertains and shall either (i) render to Puget a revised bill, consistent with such Operating Plan, pursuant to the applicable GTRSPs set forth in Exhibit A and to the Billing Provisions set forth in Part B of Exhibit B or (ii) cause to be refunded to Puget as a lump sum payment, within 30 days after the date on which such Operating Plan is so amended, an amount consistent with such Operating Plan (multiplied by Puget's Capacity Ownership Percentage).

The amount of any refund or bill payable pursuant to this paragraph 16(f)(2) shall be paid with interest on such amount calculated at a rate equal to the weighted average of Bonneville's then-outstanding bonds or other debt instruments from (and including) the date on which such resolution is accepted by the Committee to (but excluding) the date on which such amount is refunded to Puget; and

(3) If the Committee does not accept such resolution, if any, proposed by Bonneville with respect to any such exception, or if Bonneville does not propose any such resolution, then the Committee

(A) shall have the right to arbitrate, pursuant to section 14, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to subsection 13(i); and

(B) shall have the right to arbitrate, pursuant to section 15, any cost with respect to which such exception is taken to the extent that such cost is permitted to be arbitrated pursuant to section 15.

The Committee must refer to arbitration pursuant to subparagraph 16(f)(3)(A) or 16(f)(3)(B) any cost to which exception is taken as a result of any audit within eight months after the date the Committee commences such audit. Failure of the Committee to elect to so refer to arbitration any cost within such eight-month period shall be deemed to constitute waiver by the Committee of any right pursuant to this section 16 to arbitrate such cost.

(g) Puget shall have the right to participate in any audit pursuant to this section 16 only by acting through the Committee. If Puget chooses not to participate in any audit undertaken by the Committee, then Puget shall accept the findings of the Committee with respect to such audit and any resolution by the Committee and Bonneville of any inconsistency noted in any exception taken as a result of such audit.

(h) Any audits undertaken by the Committee shall be upon reasonable notice to Bonneville and at reasonable times and shall commence no more frequently than once in any 24 consecutive months. The audit rights provided in this section shall not be construed to permit a general audit of Bonneville's books, records, and documents. Audits shall be in conformance with generally accepted auditing standards.

Prior to and for the duration of any audit, Bonneville shall retain all pertinent books, records, and documents prepared in the normal course of business. After commencement of an audit pursuant to subsection 16(a), 16(b), or 16(c), the Committee may request and Bonneville shall promptly provide reasonably available supporting documentation for any cost or charge subject to audit. If the Committee fails to commence an audit pursuant to subsection 16(a), 16(b), or 16(c) within the time periods set forth in subsection 16(a), 16(b), or 16(c), such failure shall constitute waiver by Puget of any right pursuant to this section 16 to arbitrate any charge or refund billed or refunded by Bonneville.

(i) If Puget is operating pursuant to paragraph 3(b)(1), Bonneville shall have the right, at its own expense, to review Puget's books, records, and documents that directly pertain to the revenue reportable in Puget's accounting system where revenues received for wheeling for other entities would be booked for the purpose of verifying compliance with paragraph 3(b)(1). Bonneville shall have the right to perform such audit no more frequently than once every 36 months.

17. PROTECTED AREAS

Puget shall not use its Scheduling Share for transmission of power on the PNW AC Intertie from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by Bonneville unless Puget is required by regulatory authority to purchase or provide transmission for the output of such project or unless Bonneville receives sufficient demonstration that a particular project would provide benefits to Bonneville's existing or planned fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program. The Parties agree that System Sales shall not be taken into consideration in any determination of whether Puget has used its Scheduling Share for transmission of power on the PNW AC Intertie from the hydroelectric projects referred to in the immediately preceding sentence. For purposes of this section 17, "System Sale" means any sale of power or energy to Puget or by a seller of power or energy, which power or energy is not

resource-specific and is delivered to Puget at a point that connects one or more resources or transmission systems.

18. ESTABLISHMENT AND MAINTENANCE OF RATES AND RELIEF FROM REGULATORY ACTION

(a) Bonneville shall use good faith efforts to maintain in effect such of the following rates that has been approved by FERC on an interim or final basis, during the rate approval period established by FERC for such rate:

(1) any rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date;

(2) the Initial Successor Rate;

(3) the Alternative Successor Rate; and

(4) the Bonneville Successor Rate.

(b) If Bonneville's Administrator submits to FERC a rate that is different from that set forth in Exhibit B, Part A and Part B, on the Effective Date, as the first rate proposed by Bonneville (Initial Successor Rate) to replace the AC-93 rate set forth in Exhibit A or that is for a rate approval period which is less than the remainder of the Term following the expiration of the AC-93 rate, Puget may, within 90 days after Bonneville submits the Initial Successor Rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(b) except for those rights and obligations set forth in this paragraph 18(b)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

$$A - ((B/540) \times A) + I = \text{Refunded Lump Sum Payment}$$

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(b).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

I = Interest on A - ((B/540) X A), accruing from (and including) the date of Bonneville's receipt of Puget's Initial Lump Sum Payment to (but excluding) the date on which Bonneville receives Puget' notification to terminate this Agreement pursuant to this subsection 18(a), at the 5-year Treasury note rate in effect on the date on which Bonneville receives Puget's Initial Lump Sum Payment.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(b)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(b)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(b)(2)(B), Bonneville may accelerate payment to Puget of the amount of the Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(b)(2), Bonneville shall not develop a rate or charge that would

inequitably allocate to Puget and Capacity Owners other than Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

(c) If FERC approves the Initial Successor Rate, the Alternative Successor Rate (as defined in subsection 18(d)), or the Bonneville Successor Rate (as defined in subsection 18(d)) for a term less than the remainder of the Term following the expiration of the AC-93 rate, and if Bonneville's Administrator thereafter submits to FERC a rate (Replacement Rate) that is different from the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis) or that is for a rate approval period which is less than the remainder of the Term following the expiration of the Initial Successor Rate, the Alternative Successor Rate or the Bonneville Successor Rate (whichever had been approved by FERC on an interim or final basis), Puget may, within 90 days after Bonneville submits such rate to FERC and without regard to FERC's interim or final disposition of such rate, elect by written notice to Bonneville to terminate this Agreement and shall in such notice to Bonneville elect to exercise one of the two following options:

(1) Puget may elect to proceed pursuant to paragraphs 18(f)(1), 18(f)(2), and 18(f)(3); or

(2) Puget may elect to have its Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a), refunded by Bonneville subject to the following terms and conditions:

(A) This Agreement shall terminate upon the date Bonneville receives Puget's notification to terminate this Agreement pursuant to this subsection 18(c) except for those rights and obligations set forth in this paragraph 18(c)(2).

(B) Bonneville shall refund within the next three succeeding rate periods but, in any event, within 8 years after Puget has made its election for such refund (such period to begin no later than the 25th month after Bonneville's receipt of Puget's notification to terminate this Agreement and to end on the 96th month after Bonneville's receipt of such notification) in equal monthly amounts an amount equal to the "Refunded Lump Sum Payment" calculated as follows:

A - ((B/540) X A) + R = Refunded Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement.

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

R = 2.5 times the amount paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the

immediately preceding fiscal year times the ratio of (a) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the first fiscal year during the proposed rate approval period pursuant to the rate submitted by Bonneville to FERC to replace the immediately preceding annual costs rate over (b) the amount forecast to be paid pursuant to subparagraphs 9(b)(2)(A) and 9(b)(2)(B) for the same fiscal year were the immediately preceding annual costs rate to remain in effect; provided, however, that the ratio of (a) over (b) shall in no event be less than one for purposes of this subsection.

(C) Bonneville shall, subject to the immediately succeeding sentence, pay interest on the Refunded Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest payable pursuant to this subparagraph 18(c)(2)(C) shall be paid by Bonneville on the amount of each monthly amount of the Refunded Lump Sum Payment payable by Bonneville pursuant to subparagraph 18(c)(2)(B).

(D) Bonneville shall refund the Refunded Lump Sum Payment pursuant to paragraph 9(f)(4).

(E) At any time during the repayment period referenced in subparagraph 18(c)(2)(B), Bonneville may accelerate payment to Puget of the amount of Refunded Lump Sum Payment.

If Puget elects to proceed under this paragraph 18(c)(2), Bonneville shall not develop a special rate or charge that would inequitably allocate to Puget and Capacity Owners other than

Puget, or to any of them, the cost to Bonneville of the Refunded Lump Sum Payment; provided, however, that such allocation shall not be deemed to be inequitable solely because it causes the recovery of a portion of the cost to Bonneville of the Refunded Lump Sum Payment from Puget or any Capacity Owner other than Puget.

The terms of this subsection 18(c) shall be effective through December 31, 2040.

(d) If (i) FERC remands or approves a rate which materially differs from the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, or (ii) FERC grants final approval to a rate containing the terms set forth in Exhibit B, Part A and Part B, on the Effective Date, or to the Initial Successor Rate for a rate approval period of less than the remainder of the Term following the expiration of the AC-93 rate, or (iii) FERC remands or disapproves the Initial Successor Rate, then in any such event Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to develop an alternative successor rate (Alternative Successor Rate) which would place Puget in substantially the same position with respect to Puget's rights and obligations under this Agreement as if the rate schedule and Billing Provisions set forth in Exhibit B, Part A and Part B, on the Effective Date, had been approved by FERC for the remainder of the Term following the expiration of the AC-93 rate. Bonneville, Puget, and Capacity Owners other than Puget shall use good faith efforts to reach agreement on an Alternative Successor Rate within 6 months after the date of the FERC order regarding the Initial Successor Rate contemplated in this subsection 18(d) or within the time period established in such FERC order, whichever is earlier.

(1) If Bonneville, Puget, and Capacity Owners other than Puget reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, then Bonneville shall, subject

to section 7(i) of the Regional Act, submit such Alternative Successor Rate to FERC for approval and confirmation.

(2) If Bonneville, Puget, and Capacity Owners other than Puget do not reach such an agreement regarding an Alternative Successor Rate within the applicable time period referred to in the immediately preceding sentence, Bonneville shall develop a rate, which, among other things, in Bonneville's judgment, protects the rights and obligations of Puget and Capacity Owners other than Puget and, subject to section 7(i) of the Regional Act, shall submit such rate (Bonneville Successor Rate) to FERC for approval and confirmation.

Nothing in this subsection 18(d) shall limit or otherwise affect any provisions of subsection 18(b) or 18(c).

(e) If Bonneville, Puget, and Capacity Owners other than Puget are unable to agree upon an Alternative Successor Rate pursuant to subsection 18(d), or if FERC approves the Alternative Successor Rate for a period of less than 15 years or with terms and conditions that differ from the terms and conditions of the Alternative Successor Rate, or if FERC remands the Alternative Successor Rate, or if FERC approves the Bonneville Successor Rate, Puget may elect, within 6 months of any of the foregoing events, to terminate this Agreement and execute a long-term contract with Bonneville for firm wheeling on the PNW-PSW Intertie for a term not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share, pursuant to subsection 18(f).

(f) Should Puget elect to proceed pursuant to paragraph 18(b)(1) or 18(c)(1) or subsection 18(e), the Parties shall take the following steps:

(1) Puget shall provide Bonneville with written notification of its election to terminate this Agreement and with a written request for a long-term contract for firm wheeling on the PNW-

PSW Intertie for a period not less than the remaining term of the agreement(s) specified in Exhibit J for wheeling of an amount of power on the PNW-PSW Intertie up to Puget's Capacity Ownership Share.

(2) As soon as practicable after receipt by Bonneville of the written notice sent pursuant to paragraph 18(f)(1), Bonneville shall offer to Puget a long-term contract for firm wheeling on the PNW-PSW Intertie of an amount of power equal to the amount of power specified in Puget's written request pursuant to paragraph 18(f)(1), such offered contract to contain other terms and conditions substantially similar to those then being offered by Bonneville to its other firm wheeling customers for transactions on the PNW-PSW Intertie.

The termination date of this Agreement shall be the same date as the effective date of the long-term contract for firm wheeling referred to in this paragraph 18(f)(2), and such date shall in any event be no more than 6 months after Bonneville's receipt of Puget's notification pursuant to paragraph 18(f)(1).

(3) The long-term contract for firm wheeling offered to Puget pursuant to paragraph 18(f)(2) shall also contain provisions which:

(A) Require Bonneville to credit or pay (any such payment to be made pursuant to paragraph 9(f)(4)), in equal monthly amounts during the term of such long-term contract for firm wheeling, against the amount payable by Puget to Bonneville pursuant to such long-term wheeling agreement an amount equal to the "Credited Lump Sum Payment" calculated as follows:

A - ((B/540) X A) = Credited Lump Sum Payment

where:

A = The Initial Lump Sum Payment, Adjusted Lump Sum Payment, or any Revised Adjusted Lump Sum Payment, whichever has been most recently paid by Puget to Bonneville pursuant to subsection 9(a).

B = The number of months between the Effective Date and the termination date of this Agreement pursuant to this subsection 18(e).

540 = 12 months X 45-year period over which Bonneville will amortize the Initial Lump Sum Payment, Adjusted Lump Sum Payment, or such Revised Adjusted Lump Sum Payment, as the case may be.

(B) Require Bonneville, subject to the immediately succeeding sentence, to credit or pay interest on the Credited Lump Sum Payment at a rate equal to Bonneville's weighted average interest rate on Bonneville's then-outstanding bonds and on Bonneville's then-outstanding debt instruments. Such interest to be credited or paid pursuant to this provision shall be credited or paid by Bonneville on the amount of each monthly amount of the Credited Lump Sum Payment to be credited or paid by Bonneville pursuant to the provision set forth in subparagraph 18(f)(3)(A).

(C) Permit Bonneville to accelerate payment to Puget of the amount of Credited Lump Sum Payment which remains uncredited at any time during the term of such long-term contract for firm wheeling.

(g) Puget's right to terminate this Agreement pursuant to subsections 18(d) through 18(f) is a one-time only right that must be exercised after FERC action pursuant to subsection 18(d). If Puget fails to

terminate the Agreement pursuant to subsection 18(e) as prescribed therein as a result of FERC action, Puget shall have no future rights to terminate the Agreement under this section 18 as a result of FERC action.

(h) Bonneville shall use best efforts to establish and maintain in effect the AC-93 rate, set forth in Exhibit A, during the remainder of the Term, but only until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), that is confirmed and approved by FERC on an interim or final basis, becomes effective. If FERC does not confirm and approve on a final basis the AC-93 rate for a rate approval period of sufficient duration so that the AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or such other rate, becomes effective, then upon expiration of the rate approval period of such AC-93 rate, Bonneville shall submit to FERC a rate based on the methodology used to determine the AC-93 rate (revised AC-93 rate) and shall use best efforts to obtain a rate approval period for the revised AC-93 rate of sufficient duration so that the revised AC-93 rate is effective until the annual costs rate set forth in Exhibit B, or other rate submitted to FERC, pursuant to subsections 18(b) through 18(d), becomes effective. If, at any time during the Term, FERC does not confirm and approve on an interim or final basis the AC-93 rate or revised AC-93 rate for any reason other than the duration of the rate approval period, Bonneville and Puget shall use best efforts to develop a rate that would replace the AC-93 rate or revised AC-93 rate, and Bonneville shall submit such rate to FERC, pursuant to section 7(i) of the Regional Act, for confirmation and approval if such rate is agreed to by Bonneville, Puget and Capacity Owners other than Puget. If Bonneville and Puget do not succeed in developing such rate, Bonneville shall submit to FERC, pursuant to section 7(i) of the Regional Act, a rate which in Bonneville's judgment recovers Bonneville's costs. Bonneville shall bill Puget, and Puget shall pay Bonneville, in accordance with the AC-93 rate or, if FERC does not confirm and approve on an interim or final basis the AC-93 rate, the rate confirmed and approved by FERC on an interim or final basis.

Bonneville shall revise Exhibit A so that it contains, at a given time, the AC-93 or other rate confirmed and approved by FERC on an interim or final basis.

19. **EXHIBITS**

(a) Exhibits A through J attached to this Agreement are by this reference made a part of this Agreement. In the event of a conflict between any provision in Exhibits A through J and the provisions of sections 1 through 23 of this Agreement, the provisions of sections 1 through 23 of this Agreement shall prevail.

(b) Bonneville shall revise Exhibit A pursuant to subsections 18(g) and 18(h) and this subsection 19(b). The rate schedules attached hereto as Exhibit A have been conditionally or finally confirmed by FERC. If the final rate schedules which are approved by FERC are an amendment or modification of the initial rate schedules, the applicable amended or modified rate schedules and associated GTRSPs shall be attached to and made part of this Agreement effective as of the date specified in FERC's approval. The rate schedules and GTRSPs included in Exhibit A shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Regional Act and FERC rules.

(c) Upon interim or final approval by FERC of any rate submitted to FERC pursuant to subsections 18(a) through 18(g), Bonneville shall revise Exhibit B so that Exhibit B contains such rate approved by FERC as contemplated in this subsection 19(c). For purposes of this Agreement, such rate shall be effective as of the date of effectiveness specified in FERC's approval of such rate. Subject to the provisions of subsections 18(a) through 18(g), the rate schedule set forth in Exhibit B, Part A and Part B, on the Effective Date, shall be replaced by successor rate schedules and provisions pursuant to section 7(i) of the Northwest Power Act and applicable FERC rules.

(d) Bonneville shall revise or modify Exhibit C from time to time to reflect changes hereafter agreed to in writing by the Parties in Puget's Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share.

(e) Bonneville shall revise Exhibit D pursuant to subsection 9(a). Revision or modification of Exhibit D shall not require an executed amendment or revision to this Agreement.

(f) Not more frequently than annually, Bonneville shall review and, as appropriate, revise Exhibit E, Part A, in accordance with Bonneville's standard methodology and formula for calculation of average losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie. Such methodology and formula are intended to forecast average annual actual losses incurred by Bonneville in providing transmission on Bonneville's PNW AC Intertie Operational Transfer Capability. Any changes to the loss methodology or formula, other than numerical values, shall be made only after consultation with the Committee. During such consultation, Bonneville shall provide to the Committee material pertinent to such changes to the loss methodology or formula. Upon conclusion of any review of the loss factor in Exhibit E, Part A, Bonneville shall present the results of its review, including any revisions to the loss factor in Exhibit E, Part A, to the Committee as part of the Operating Plan pursuant to section 13. If the Committee pursues arbitration pursuant to subsection 10(b) and section 14, Bonneville shall revise Exhibit E, Part A, to reflect the selection of the arbitrators pursuant to subsection 14(j).

(g) Bonneville shall revise the loss factor in Exhibit E, Part B, as necessary to equal the same factor for average losses as Bonneville generally applies to transmission over Bonneville's share of the PNW-PSW Intertie. Revision of Exhibit E, Part B, shall not require an executed amendment or revision to this Agreement.

(h) Bonneville shall revise Exhibit F as appropriate to reflect the facilities in Bonneville's PNW AC Intertie. Revision or modification of

Exhibit F shall not require an executed amendment or revision to this Agreement.

(i) Bonneville shall revise Exhibit G as appropriate to reflect the complete list of all of the Capacity Owners and their respective Capacity Ownership Shares and Capacity Ownership Percentages from time to time pursuant to this Agreement.

(j) Bonneville shall revise Exhibit H as appropriate to reflect all provisions required by statute or Executive Order. Revision or modification of Exhibit H shall not require an executed amendment or revision to this Agreement.

(k) Bonneville shall revise Exhibit I to reflect changes as agreed to in writing by Puget and Capacity Owners other than Puget.

(l) Bonneville shall revise Exhibit J as mutually agreed to in writing by the Parties.

20. **RULES OF LAW**

(a) Bonneville and Puget agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) This Agreement shall not be construed to establish a partnership, association, agency relationship, joint venture, or trust. Neither Party shall be under the control of or shall be or represent itself as, the agent of, or have a right or power to bind, the other Party without the other's express written consent, except as provided in this Agreement.

(c) All applicable law is incorporated in and made part of this Agreement.

21. NOTICES

(a) Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be served, given, or made if delivered in person or sent by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons addressed as set forth below:

To Bonneville:

Group Vice President for Marketing, Conservation and Production
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

To Puget:

Vice President Power Planning
Puget Sound Power & Light Company
411 108th Avenue NE 15th Floor
Bellevue, WA 98004-5515

To Seattle:

Director, Power Management Division
Seattle City Light
1111 Third Avenue, Room 420
Seattle, WA 98101

To PNGC:

Director of Power Management
Pacific Northwest Generating Cooperative
711 NE Halsey Street, Suite 200
Portland, OR 97232

To Snohomish:

Manager of Power Supply
Public Utility District No. 1 of Snohomish
County, Washingon
2320 California Street
P.O. Box 1107
Everett, WA 98201

To Tacoma:

Light Division Superintendent
Tacoma Public Utilities
3628 S. 35th Street
Tacoma, WA 98411

(b) Either Party may, by written notice to the other Party pursuant to subsection 21(a), change the address set forth in subsection 21(a) for the notifying Party.

(c) All notices pursuant to this Agreement shall be effective on the date of receipt.

22. **WAIVER**

Any waiver at any time by a Party of its rights with respect to any matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent or other matter. Except as otherwise provided herein or as agreed in writing by the Parties, no provision in this Agreement may be waived except as documented or confirmed in writing.

23. **MISCELLANEOUS**

(a) **Effect of Section Headings**

Section headings and subheadings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of provisions of this Agreement.

(b) **Amendments**

Except as may be expressly otherwise provided in this Agreement, this Agreement may be amended only with the express written consent of both of the Parties, and no provision of this Agreement shall be varied or contradicted by any oral agreement, course of dealing or performance or any other matter not hereafter set forth in a written agreement signed by both of the Parties.

(c) **Entire Agreement**

This Agreement constitutes, on and as of the date hereof, the entire agreement of the Parties with respect to the subject matter of this Agreement, and all prior understandings or agreements, whether written or oral, between the Parties with respect to the subject matter of this Agreement are hereby superseded in their entireties.

(d) **No Third Party Beneficiaries**

There are no third party beneficiaries of this Agreement. This Agreement shall not be construed to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, obligation, or undertaking established herein.

(e) **Regulatory Approvals**

Each Party shall use its best efforts to obtain and maintain in effect regulatory approvals that are necessary to permit such Party to perform its obligations under this Agreement in accordance with its terms and conditions. Neither Party shall oppose in any way or seek to alter or amend the terms and conditions of this Agreement by application to or participation in any application of any regulatory authority or court having jurisdiction. Puget shall not oppose in any way or seek to alter or amend the terms or conditions of the annual costs rate set forth in Exhibit B, the CO-94 rate, the AC-93 rate, or

any rate described in section 18 that is agreed to by the Parties subsequent to each entering into this Agreement, in any proceeding pursuant to section 7 of the Pacific Northwest Electric Power Planning and Conservation Act before FERC or in any court of competent jurisdiction.

(f) **Other Capacity Ownership Agreements**

If Bonneville offers to enter into (i) a Capacity Ownership Agreement with any other Capacity Owner or (ii) any written amendment of any Capacity Ownership Agreement (other than this Agreement), then Bonneville shall offer to Puget an amendment of this Agreement that contains the terms and conditions of such Capacity Ownership Agreement with such other Capacity Owner or of such written amendment, as the case may be. Bonneville shall advise, and use reasonable efforts to consult with, Puget during the development or consideration of any offer to any Capacity Owner other than Puget to enter into a Capacity Ownership Agreement or any amendment of such agreement.

(g) **Singular and Plural Forms**

For purposes of interpreting and construing this Agreement, the singular form of a word shall include its plural and the plural form of a word shall include its singular, unless otherwise expressly provided by this Agreement.

(h) **Performance Pending Dispute**

Except as otherwise expressly provided in this Agreement, pending resolution of any dispute, issue, or controversy arising under this Agreement, the Parties shall each continue performance of their respective obligations pursuant to this Agreement.

(i) **Time Periods**

For purposes of calculating any time period prescribed by this Agreement, if the last day of the time period falls on a day that is not a Working Day, then the last day of the time period shall be the first Working Day following such day as would otherwise be the last day of the time period.

(j) **Double Counting**

In developing rates or charges under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act for any rate period, Bonneville shall not set rates or charges that recover, more than once, the costs associated with capital projects that are paid or forecast to be paid under the CO-94 rate and the AC-93 rate and annual costs rate set forth in Exhibit B, or the remaining Bonneville's PNW AC Intertie costs forecast to be paid under the AC-93 rate and annual costs rate set forth in Exhibit B. Bonneville's forecast of revenues chargeable under the CO-94 rate, AC-93 rate, and annual costs rate set forth in Exhibit B shall be based on the best available information, including information provided pursuant to section 13 of this Agreement.

In the event Bonneville proposes any wheeling rate for transmission service on Bonneville's main grid that includes costs of the PNW AC Intertie, such proposed rate shall include a credit or other mechanism that ensures that Puget is not charged any of the PNW AC Intertie costs for deliveries of power that utilize up to the Puget's Capacity Ownership Share, as that term is defined in this Agreement.

(k) **Committee Action**

Each of the Parties agrees that to the extent it is provided in sections 13, 14, and 16 that the Committee shall take any action or shall make any decision, such action or decision shall be taken or made, as the case may be, by the Committee, and not by Puget acting individually.

(l) **Fiscal Year**

For purposes of this Agreement, the term "fiscal year" shall mean Bonneville's fiscal year.

(m) **Rights and Remedies Cumulative**

All rights and remedies of either Party under this Agreement and at law and in equity shall be cumulative and not mutually exclusive and the exercise of one right or remedy shall not be deemed a waiver of any other right or remedy. Nothing contained in any provision of this Agreement shall be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement, at law or in equity.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ WALTER E. POLLOCK
Group Vice President for Marketing,
Conservation and Production

By Walter E. Pollock
Group Vice President for Marketing,
Conservation and Production

Name Walter E. Pollock
(Print/Type)

October 11, 1994

Date October 11, 1994

Puget Sound Power & Light Company

By J R Lauckhart

/s/ J. R. LAUCKHART

Name J. R. Lauckhart
(Print/Type)

Title VP Power Planning

Vice President, Power Planning

Date 9/26/94

September 26, 1994

Effective Date _____

CO-94, AC-93, IS-93 Rate Schedules and General Transmission Rate Schedule Provisions

Schedule CO-94
CAPACITY OWNERSHIP RATE SCHEDULE

Section I. Availability

This schedule applies to all agreements which provide life-of-facilities capacity rights to non-Federal participants (Capacity Owners) in 725 MW of Bonneville's PNW AC Intertie and any upgrades thereto. Service under this schedule is subject to Bonneville's General Transmission Rate Schedule Provisions.

Section II. Rate

The charge for capital and related costs for non-Federal capacity ownership in Bonneville PNW AC Intertie shall be determined by the methodologies set out in Section III below.

Section III. Determination of Rate

A. Capacity Ownership Price

The charge for capacity ownership in Bonneville's PNW AC Intertie shall be the Capacity Ownership Share of the actual capital and related costs of facilities as determined by the formula shown below. The Capacity Ownership Share shall be determined pursuant to the Capacity Ownership agreement.

$$\frac{(A - B) + C + D}{E} = \text{Capacity Ownership Price in \$/kW}$$

Capacity Ownership Price in $/kW x number of kW contracted for by Capacity Owner = Capacity Owner's payment to Bonneville

Where:

A = Bonneville's cost of new facilities for the Third AC Intertie, which increased the n transfer capability of the PNW AC Intertie by approximately 1600 MW, is the construction costs (including direct, indirect and overhead costs) of the facilities associated with the Third AC Intertie System Reinforcements and the Alvey-Meri

Transmission Line (also known as Eugene-Medford 500-kV Transmission Line), referred to jointly as the Third AC Intertie Project.

B = Bonneville's cost of new facilities needed for the first 800 MW increment of the 1600 MW Third AC Intertie Project, which includes a portion of the construction costs (including direct, indirect and overhead costs) associated with the Third AC Intertie System Reinforcement.

A-B = The cost of new facilities for the second 800 MW increment of the 1600 MW Third AC Intertie Project (presented in Exhibit C of the Capacity Ownership agreement).

C = Allowance for Funds Used During Construction (AFUDC) constitutes interest on the funds used for the Third AC Intertie Project while it was under construction. AFUDC is calculated and capitalized consistent with FERC requirements as described in FERC's Uniform System of Accounts, 18 CFR, Part 101, Electric Plant Instructions, 3.A(17). The AFUDC applies to that amount capitalized on the second 800 MW increment of the 1600 MW Third AC Intertie Project, or A - B.

D = Book value of existing Bonneville support facilities that are dedicated to the PNW AC Intertie equal to $19,100,000.

E = 725,000 kW, which equals Bonneville's share of the second 800 MW of the Third AC Intertie.

B. PNW AC Intertie Upgrade Price

The charge for upgrades to Bonneville's PNW AC Intertie facilities that occur after December 1993, and which result in an increase of rated transfer capability, shall be the Capacity Ownership Share of the capital and related costs of the upgrade. The Capacity Ownership Share of any upgrades shall be determined pursuant to the Capacity Ownership agreement. The capital costs shall consist of the construction costs (including direct, indirect and overhead costs) and AFUDC (as described in Section III.A. above) of the facilities associated with such upgrades.

Section IV. Adjustments and Special Provisions

A. Initial Lump Sum Payment

Capacity Owners shall make an initial, lump sum payment of an estimate of the Capacity Ownership Price equal to $215/kW pursuant to the Capacity Ownership agreement.

B. Adjustment to Reflect Actual Construction Costs

Approximately December 1995 or as soon as practicable thereafter, the Capacity Owner's initial lump sum payment shall be adjusted to reflect the difference between the actual and the estimated Capacity Ownership Price. The actual Capacity Ownership Price shall be determined pursuant to Section III.A. above. There will be no adjustment for the book value of the support facilities dedicated to the PNW AC Intertie. Capacity Owners will either receive a refund, with interest, from Bonneville or make an additional payment, with interest, to Bonneville. Bonneville shall compute interest using the weighted average interest rate on Bonneville's outstanding bonds.

C. PNW AC Intertie Upgrade Payments

Capacity Owners shall pay a share of the upgrades to Bonneville's PNW AC Intertie in the manner and time to be determined when participation in such upgrades are agreed to pursuant to the Capacity Ownership agreement.

Schedule AC-93

Southern Intertie Annual Cost

SECTION I. AVAILABILITY

This schedule is applicable to all parties (New Owners) that execute PNW AC Intertie Capacity Ownership Agreements (Agreements) and will be effective on the date described in the Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The rate charges reflect the terms of the Memorandum of Understanding (MOU), signed in the Fall of 1991, between BPA and potential New Owners. The MOU provides for the payment by New Owners of their prorated share of: (1) BPA's annual operations, maintenance, and general plant expense (including applicable overheads) properly chargeable to the AC Intertie facilities; and (2) BPA's share of capitalized replacements on the AC Intertie. The monthly charge shall be the sum of the charges specified in sections II.A and II.B.

A. Operations, Maintenance, and General Plant

The monthly charge shall equal $325 per megawatt of billing demand.

B. Replacements

The monthly charge shall equal $0 per megawatt of billing demand.

SECTION III. ADJUSTMENT TO REPLACEMENTS RATE

A. Determination of Billing Adjustment

New Owners will receive a billing adjustment if BPA incurs AC Intertie replacement cost during the rate period. The Replacements Rate Adjustment equals:

$$\frac{\text{AC Intertie work orders (\$000)} * \%}{\text{725 MW} * \text{\# months}}$$

where:

"# months" equals: (1) the number of months that this rate schedule is in effect during the fiscal year for the Initial Replacements Rate Adjustment; or (2) the number of months in the rate period for the Final Replacement Rate Adjustment; and

"%" equals the New Owners' percentage share of BPA's total AC Intertie Rated Transfer Capability as specified in the Agreements.

B. Initial Replacements Rate Adjustment

New Owners will receive a billing adjustment for each fiscal year that BPA incurs AC Intertie replacement cost. At the end of each fiscal year, the cost associated with AC Intertie capital replacement work orders that have closed during the fiscal year will be determined. The unit rate that would result using these closed work orders is the basis of the Initial Replacements Rate Adjustment.

1. Notice Provisions

Following each fiscal year, BPA shall notify all New Owners by December 1 of the proposed Replacements Rate Adjustment. BPA will provide the calculation of the adjustment and a short description of the work performed and the associated cost used as the basis for the billing adjustment. In addition to written notification, BPA may, but is not obligated to, hold a public meeting to clarify its determinations.

Written comments on the Initial Replacements Rate Adjustment will be accepted through the end of January. Consideration of comments submitted by the New Owners may result in the billing adjustment differing from the initially proposed adjustment. BPA shall notify all New Owners of the Initial Replacements Rate Adjustment by the last day of February.

2. Adjustment of Monthly Bills

An adjustment will be made on the New Owner's monthly bill prepared during March. The Initial Replacements Rate adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal year (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal year). The Initial Replacements Rate Adjustment will appear as a charge to the New Owner on the monthly bill prepared during March.

C. Final Replacements Rate Adjustment

The actual costs associated with the AC Intertie capital replacement work orders that occur during the rate period may change after BPA performs its final analysis of the work orders. BPA shall compare the unit rate for the rate period using the results of the final work order analysis to the weighted average of the unit rates from the Initial Replacements Rate Adjustments.

1. Notice Provisions

BPA shall notify all New Owners in May 1998 of the results of the calculations, an explanation of work order change(s), and any resulting billing adjustment. Written comments from New Owners will be accepted through the end of June. BPA shall notify all New Owners of the Final Replacements Rate Adjustment by July 31. Consideration of comments submitted by the New Owners may result in the Final Replacements Rate Adjustment differing from the initially proposed adjustment.

2. Adjustment of Monthly Bills

If the absolute value of the Final Replacements Rate Adjustment is greater than or equal to $1 per megawatt per month, an adjustment will be made on the New Owner's monthly bill prepared during August. For each New Owner, the Final Replacements Rate Adjustment will be multiplied by the sum of the monthly billing factors from the relevant fiscal years (i.e., the New Owner's share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability multiplied by the number of months that this rate schedule is effective during the fiscal years). The Final Replacements Rate Adjustment will appear as a charge or credit to the New Owner on the monthly bill prepared during August. Interest, as determined by BPA's Office of Financial Management, will be included in any adjustment.

SECTION IV. BILLING FACTOR

The billing demand shall be the New Owner's capacity ownership share in megawatts of BPA's PNW AC Intertie Rated Transfer Capability as specified in the Agreement.

Schedule IS-93

Southern Intertie Transmission

SECTION I. AVAILABILITY

This schedule supersedes IS-91 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Transmission Rate

The charge for nonfirm transmission of non-BPA power shall be 3.11 mills per kilowatthour of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Transmission Rate

The charge for firm transmission service shall be $0.706 per kilowatt per month of billing demand and 1.69 mills per kilowatthour of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSPs)

A. Approval of Rates

These rate schedules and GTRSPs shall become effective upon interim approval or upon final confirmation and approval by FERC. BPA will request FERC approval effective October 1, 1993.

B. General Provisions

These 1993 Transmission Rate Schedules and associated GTRSPs are virtually identical to and supersede BPA's 1991 Transmission Rate Schedules and GTRSPs (which became effective October 1, 1991) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act, and the Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992).

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from: (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

C. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

D. Federal Columbia River Transmission System

The transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network as shown in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

I. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

J. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

K. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the interconnection terminals.

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer Substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary Substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI and the Main Grid or the secondary POD, or the Main Grid and the secondary POD.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation; when completed, the Third AC facilities, which include Captain Jack Substation and the Alvey-Meridian 500 kV AC line; one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border; and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the Western Systems Power Pool Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Billing Month

For charges based on scheduled quantities, the billing month is the calendar month. For charges based on metered quantities, the billing month is defined as the interval between scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

4. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

5. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

6. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

7. Revised Bills

As necessary, BPA may render a revised bill.

a. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference and the date of the revised bill shall be its date of issue.

Annual Costs Rate

A. PROPOSED SOUTHERN INTERTIE ANNUAL COST RATE

SECTION I. AVAILABILITY

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule is subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

SECTION II. RATE

A. Operations

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is

amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

B. Maintenance

The monthly charge equals:

$$\frac{\text{Maintenance Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

C. General Plant

The monthly charge equals:

$$\frac{\text{General Plant Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

D. Other Costs

The monthly charge equals:

$$\frac{\text{Other Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

E. Contracts and Rates

The monthly charge equals:

$$\frac{\text{Contracts and Rates Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the

month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

F. Power Scheduling

The monthly charge equals:

$$\frac{\text{Power Scheduling Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan

pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

G. End of Term

The monthly charge shall equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

H. Replacements and Reinforcements

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains.

A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

B. BILLING PROVISIONS

I. General Provisions

A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

C. Definition of Terms

The meaning of terms used in the AC-95 rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

II Billing Information

Payment of Bills

Charges pursuant to the AC-95 rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

(1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

(2) Billing Month

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

(3) Due Date

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

(4) Late Payment

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Transmission Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Transmission Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

(5) Disputed Bills

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to

be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

(6) Revised Bills

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or pursuant to an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

Capacity Ownership Share, Capacity Ownership Percentage, Scheduling Percentage, and Scheduling Share

Capacity Ownership Share	=	400 MW
Capacity Ownership Percentage	=	Capacity Ownership Share ÷ Bonneville's PNW AC Intertie Rated Transfer Capability[1]
Scheduling Percentage	=	Capacity Ownership Share ÷ PNW AC Intertie Rated Transfer Capability
Scheduling Share	=	Scheduling Percentage × PNW AC Intertie Operational Transfer Capability

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1/ As of the Effective Date, Bonneville's PNW AC Intertie Rated Transfer Capability in a north-to-south direction, calculated in accordance with the Northwest Intertie Agreements equals 3450 MW (total PNW AC Intertie Rated Transfer Capability (4800 MW) – Portland's PNW AC Intertie Rated Transfer Capability (950 MW) – PacifiCorp's PNW AC Intertie Rated Transfer Capability (400 MW)).

Lump Sum Payment Calculation

A. SECOND 800 MW COSTS, ESTIMATED[1], ACTUAL[2], AND REVISED ACTUAL[3]

($ in Thousands)

Facilities whose costs will be adjusted using change Between Estimate and Actual		(1) BPA's Costs Estimated	(2) BPA's Costs Actual	BPA's Costs Revised Actual
1.	Alvey (Marion-Alvey Caps)	$5,739		
2.	Slatt (Loop in - Breaker)	3,044		
3.	Grizzly (BPA Breakers)	11,044		
4.	Loop into Slatt	656		
5.	Malin-Meridian loop into Captain Jack	982		
6.	Alvey Substation - BPA	8,168		
7.	Dixonville - PacifiCorp	8,635		
8.	Meridian - PacifiCorp	6,548		
9.	Power System Control	3,575		
10.	Alvey-Spencer - BPA	1,346		
11.	Spencer-Dixonville - PacifiCorp	20,388		
12.	Dixonville-Meridian - PacifiCorp	32,140		
	SUBTOTAL	102,265		
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent				
13.	Captain Jack (BPA Breakers)	$14,335		
14.	Captain Jack (Communication and Control)	5,100		
15.	Captain Jack (Series Capacitors)	722		
16.	Power System Control	5,596		
17.	Captain Jack line to Oregon-Calif. border	5,724		
	SUBTOTAL	$31,477		
	50 PERCENT OF SUBTOTAL	15,739		
	TOTAL	$118,004		

1/ Based on mid-1989 program planning levels.

2/ Actual costs will be available approximately December 1995, or as soon as practicable thereafter. Supporting documentation will be provided including work orders and accounting data for each line item.

3/ For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the revised actual costs of facilities pertaining to each such calculation of the Revised Adjusted Capacity Ownership Price.

B. INITIAL, ADJUSTED, AND REVISED ADJUSTED CAPACITY OWNERSHIP PRICE[1]

($ in Millions)

	Cost Item	(1) Initial Capacity Ownership Price	(2) Adjusted Capacity Ownership Price	Revised Adjusted Capacity Ownership Price[2]
1.	Second 800 MW	$118	$___	$___
2.	AFUDC[3] on Second 800 MW	+ 19	+ ___	+ ___
3.	Existing Support Facilities	+ 19.1	+ 19.1[4]	+ 19.1[4]
4.	Total Cost[5]	$156	$___	$___
5.	PRICE PER KW (CO-94)[6]	$215	$___	$___

1/ Initial, Adjusted, and Revised Adjusted Capacity Ownership Price are determined in accordance with the CO-94 rate in Exhibit A.

2/ Bonneville may make multiple calculations of the Revised Adjusted Capacity Ownership Price pursuant to paragraph 9(a)(3). For each calculation of the Revised Adjusted Capacity Ownership Price, Bonneville will include the column pertaining to such calculation and the columns for any previous calculations of the Revised Adjusted Capacity Ownership Price.

3/ AFUDC will be calculated in accordance with the CO-94 rate in Exhibit A.

4/ Not adjusted in calculating the Adjusted Capacity Ownership Price or the Revised Adjusted Capacity Ownership Price.

5/ Bonneville's indirect costs and overhead costs shall be included. Such indirect costs and overhead costs shall be allocated or distributed to the Third AC Intertie Project using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs to all of Bonneville's other capital projects during the time the Third AC Intertie Project was under construction. Such allocation or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's Third AC Intertie Project than with respect to any other transmission projects under construction at the same time.

6/ Price per kW is derived by dividing the Total Cost by 725 MW.

C. INITIAL LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Initial Capacity Ownership Price	X	$215 ($215,000/MW)
3.	Initial Lump Sum Payment[1]	=	$86,000,000
4.	Deduction: Negotiation Deposit with Interest[2]	-	
5.	Due to Bonneville:	=	

1/ Initial Lump Sum Payment is calculated in accordance with section IV.A of the CO-94 rate in Exhibit A.

2/ Interest is calculated as specified in Bonneville's April 23, 1993, letter to Puget. The rate of interest for the computation is the interest rate applicable to 3-month Treasury Bills as specified in the FEDERAL RESERVE Statistical Release G.13. The rates are determined for the 3-month yield reported on the first day of the month of receipt of the negotiation deposit and on the first day of each subsequent third month thereafter. Interest is compounded quarterly from May 11, 1993, through the date Bonneville receives payment pursuant to paragraph 9(a)(1).

D. ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Adjusted Capacity Ownership Price	X	$
3.	Adjusted Lump Sum Payment[1]	=	
4.	Initial Lump Sum Payment	–	_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A.

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from the date Bonneville receives payment pursuant to paragraph 9(a)(1) through the date Bonneville or Puget receives payment pursuant to subparagraph 9(a)(2)(B).

E. REVISED ADJUSTED LUMP SUM PAYMENT

1.	Puget's Capacity Ownership Share	=	400 MW
2.	Current Revised Adjusted Capacity Ownership Price	X	$
3.	Current Revised Adjusted Lump Sum Payment[1]	=	
4.	Adjusted Lump Sum Payment/immediately preceding Revised Adjusted Lump Sum Payment	-	_____
5.	SUBTOTAL due to Bonneville, or Refund Due to Puget	=	
6.	Interest[2]	+	
7.	Due to Bonneville, or Refund due to Puget	=	

1/ Revised Adjusted Lump Sum Payment is calculated in accordance with the CO-94 rate in Exhibit A. Bonneville will calculate a Revised Adjusted Lump Sum Payment each time a Revised Adjusted Capacity Ownership Price is calculated pursuant to paragraph 9(a)(3).

2/ Interest will be calculated in accordance with the CO-94 rate in Exhibit A using the weighted average interest rate on Bonneville's outstanding bonds. Simple interest will be accrued from (a) the date Bonneville or Puget receives payment with respect to the Adjusted Lump Sum Payment pursuant to paragraph 9(a)(2)(B) or (b) the date Bonneville or Puget receives payment with respect to the Revised Adjusted Lump Sum Payment immediately preceding the current Revised Adjusted Lump Sum Payment through the date Bonneville or Puget receives payment with respect to the current Revised Adjusted Lump Sum Payment pursuant to subparagraph 9(a)(3)(B).

Transmission Loss Factors

A. The transmission loss factor to be applied to Puget's schedules for transactions transmitted on Puget's Scheduling Share shall be 2.5 percent.

B. The transmission loss factor to be applied to Puget's schedules for transactions transmitted pursuant to subparagraph 3(b)(1)(C) shall be 3.0 percent.

Bonneville's PNW AC Intertie

A. TRANSMISSION LINE FACILITIES

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	McNary-John Day 500 kV Line Loop into Slatt: • McNary-Slatt Str. 108/1 to substation dead end tower, 155 meters • Slatt-John Day Str. 1/1 to substation dead end tower, 194 meters	100	100
2.	John Day-Grizzly No. 1 500 kV	100	100
3.	John Day-Grizzly No. 2 500 kV	100	100
4.	Grizzly-Captain Jack No. 1 500 kV	100	100
5.	Captain Jack-Malin No. 1 500 kV	100	100
6.	Buckley-Grizzly 500 kV	100	57
7.	Grizzly-Summer Lake 500 kV	100	57
8.	500 kV double circuit between Buckley and Marion that supports the Buckley-Marion No. 1 and the Ashe-Marion No. 2 500 kV circuits (Str. No. 1/3 to Marion, 159 km)	100	25
9.	Marion-Alvey 500 kV	100	50
10.	Captain Jack-COB (10 km) 500 kV	100	100
11.	Alvey-Dixonville 500 kV	50	100
12.	Dixonville-Meridian 500 kV	50	100

B. SUBSTATION FACILITIES 1/ 2/

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
1.	**Slatt 500 kV** (Dispatch one-line diagram No. 228962) John Day line terminal		
	• New Breaker D#5021	100	100
	• Existing 500 kV MOD D#5020/7022	100	100
	• New 500 kV MOD D#5022	100	100
	• Existing 500 kV MOD D#5019	100	50
	• Existing Breaker D#5018	100	50

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
McNary line terminal		
• 500 kV MOD D#5023/7847	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
2. **John Day 500 kV** (Dispatch one-line diagram No. 132281)		
Grizzly No.2 line terminal		
• Breaker D#4131	100	50
• Breaker D#4134	100	100
• MOD D#4132	100	50
• MOD D#4133/7867	100	100
• MOD D#4135	100	100
• Associated Line PTs	100	100
Grizzly No.1 line terminal		
• Breaker D#4140	100	50
• Breaker D#4143	100	100
• MOD D#4141	100	50
• MOD D#4142/7869	100	100
• MOD D#4144	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Station General		
3. **Buckley 500 kV, Gas Insulated Substation** (Dispatch one-line diagram No. 232583)		
Slatt No. 1 line terminal		
• Breaker D#4967	100	57
• Isolating switch D#4966/7328	100	57
• Isolating switch D#4968/7355	100	57
• Ground switch D#7415	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Summer Lake No. 1 line terminal		
• Breaker D#4961	100	57

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Isolating switch D#4960/7312	100	57
• Isolating switch D#4962/7313	100	57
• Ground switch D#7311	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Marion No. 1 line terminal		
• Breaker D#4964	100	57
• Isolating switch D#4963/7314	100	57
• Isolating switch D#4965/7321	100	57
• Ground switch D#7477	100	57
• Associated Terminal Arresters	100	57
• Associated Line PTs	100	57
Station General		
4. **Marion 500 kV** (Dispatch one-line diagram No. 136180)		
Buckley line terminal		
• Breaker D#4389	100	50
• Breaker D#4386	100	25
• MOD D#4387	100	25
• MOD D#4390	100	50
• MOD D#4388/7751	100	50
• Associated Line PTs	100	50
Alvey line terminal		
• Breaker D#4374	100	50
• Breaker D#4377	100	25
• MOD D#4376	100	25
• MOD D#4375/7922	100	50
• MOD D#4373	100	50
• Associated Line PTs	100	50
Station General		
5. **Alvey 500 kV** (Dispatch one-line diagram No. 121424)		
Bank No. 5 terminal		
• Breaker D#5081	50	100
• MOD D#5080	50	100
• MOD D#5082	50	100
• MOD D#5090	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#5089/8157	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Marion No. 1 line terminal		
• Breaker D#5084	50	100
• MOD D#5083/8155	50	100
• MOD D#5085	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
Dixonville No. 1 line terminal		
• Breaker D#5087	50	100
• MOD D#5086/8156	50	100
• MOD D#5088	50	100
• Associated Terminal Arresters	50	100
• Associated Line PTs	50	100
500 kV Series Capacitor Bank (Marion-Alvey 500 kV line)	50	100
• MODs D#5100/8160,5101/8159, 5102/8158	50	100
• Bypass breaker D#5103	50	100
Station General		

6. **BPA/PacifiCorp Dixonville 500 kV Station** (PacifiCorp's one-line diagram PD-40020)

Note: PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299, as revised or amended.

For Alvey and Meridian line terminals		
• Breakers 11U1, 11U2, 11U3	50	100
• Isolating MODs 11U701, 11U700/ 11U507, 11U702, 11U703/11U505, 11U704, 11U705/11U506, 11U706, 11U707, 11U708/11U501	50	100
• Two sets of line terminal PTs	50	100
• Two sets of line terminal arresters	50	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Series Capacitor Bank in Alvey-Dixonville 500 kV line and associated isolating devices	50	100
• 180 MVAR Shunt Reactor Bank S664, 665, 666, 667 and associated arresters, PTs, and isolating devices	50	100
Station General		
7. **BPA/PacifiCorp Meridian 500 kV Yard** (PacifiCorp's one-line diagram PD-32976)		
Note: 'PacifiCorp will be invoicing BPA for any future replacements of these items listed consistent with Exhibit C of Bonneville-PacifiCorp Amendatory Agreement No. 2 to Contract No. DE-MS79-86BP92299.		
For Dixonville line terminal		
• Breakers 11R2, 11R6	50	50
• Isolating MODs 11R702, 11R703/ 11R501, 11R704, 11R710, 11R711	100	100
• One set of line PTs	50	100
• One set of line terminal arresters for the Dixonville line and one set for the Captain Jack line	50	100
• 180 MVAR Shunt Reactor Bank S690, 691 ,692, 693 and associated arresters, PTs, and isolating devices	50	100
• Series Capacitor Bank in the Dixonville-Meridian 500 kV line and associated isolating devices.	50	100
Station General		
8. **Grizzly 500 kV** (Dispatch one-line diagram No. 103924)		
John Day No. 1 line terminal		
• Breaker D#4058	100	100
• Breaker D#5040	100	100
• MOD D#4059	100	100
• MOD D#4057/7848	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4056	100	100
• MOD D#5039	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
John Day No. 2 line terminal		
• Breaker D#4042	100	100
• Breaker D#4046	100	100
• MOD D#4043	100	100
• MOD D#4044/7845	100	100
• MOD D#4045	100	100
• MOD D#4047	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Buckley No. 1 line terminal		
• Breaker D#5031	100	100
• Breaker D#5028	100	100
• MOD D#5032	100	100
• MOD D#5030/8122	100	100
• MOD D#5029	100	100
• MOD D#5027	100	100
• Associated Line PTs	100	100
Captain Jack No. 1 line terminal		
• Breaker D#5037	100	100
• Breaker D#5034	100	100
• MOD D#5038	100	100
• MOD D#5036/8123	100	100
• MOD D#5035	100	100
• MOD D#5033	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Summer Lake line terminal		
• Breaker D#5025	100	100
• MOD D#5026/8121	100	100
• MOD D#5024	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
180 MVAR Reactor Bank No. 1	100	100
• Breaker D#4222	100	100
• Isolating Switch D#4060	100	100
• Associated Arresters	100	100
300 MVAR Reactor Bank No. 2	100	100
• Breaker D#4720	100	100
• Isolating Switch D#4719	100	100
• Associated Arresters	100	100
• 300 MVAR Reactor Bank No. 3 and Neutral Reactor	100	100
• Breaker D#4038	100	100
• Isolating Switch D#4062	100	100
• Neutral isolating switch D#4109/4081	100	100
• Associated Arresters	100	100
• Associated PTs	100	100
• North Main Bus 500 kV PTs	100	100
• South Main Bus 500 kV PTs	100	100
Station General		
9. **Sand Spring 500 kV Compensation Station** (Dispatch one-line diagram No. 142239)		
Series Cap.Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
10. **Fort Rock 500 kV Compensation Station** (Dispatch one-line diagram No. 142237)		
Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
Series Cap. Bank No. 3 (Grizzly-Summer Lake line) and associated equipment	100	100
Station General		
11. **Sycan 500 kV Compensation Station** (Dispatch one-line diagram No. 142238)		

		% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
	Series Cap. Bank No. 1 (Grizzly-Captain Jack line) and associated equipment	100	100
	Series Cap. Bank No. 3 (Summer Lake-Malin line) and associated equipment but **excluding** the bypass MOD D#5065 and transmission tower	65	100
	Station General		
12.	**Summer Lake 500 kV** (Dispatch one-line diagram No. 232667)		
	Grizzly line terminal (formerly Buckley-Ponderosa Tap)		
	• Breaker D#4959	100	57
	• MOD D#4955	100	57
	• MOD D#4956/7309	100	57
	• Associated Terminal Arresters	100	57
	• Associated Line PTs	100	57
	Malin line terminal		
	• Line protective relays	0	100
	Station General		
13.	**Malin 500 kV** (Dispatch one-line diagram No. 103923)		
	Captain Jack No. 1 line terminal		
	• Breaker D#4066	100	100
	• Breaker D#4064	100	100
	• MOD D#4068	100	100
	• MOD D#4067/7849	100	100
	• MOD D#4065	100	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 1 terminal		
	• Breaker D#4186	50	100
	• MOD D#4063/7970	100	100
	• MOD D#4185	50	100
	• MOD D#4187	50	100
	• Associated Terminal Arresters	100	100
	• Associated Line PTs	100	100
	Round Mountain line No. 2 terminal		

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• Breaker D#4582	50	100
• MOD D#4583	50	100
• MOD D#4581	50	100
• MOD D#4074/7856	75	100
Grizzly No. 2/Round Mountain No. 2 line position		
• Breaker D#4072	75	100
• MOD D#4073	75	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	50	100
300 MVAR Shunt Reactor Bank No. 1 and associated arresters and isolating devices (D#4327, 4393)	100	100
2-239 MVAR Shunt Cap. Banks and associated isolating devices (D#4183, 4181, 4184, 4182, 8065, 8066)	100	100
Line protective relays for Summer Lake line	0	100
Station General		
14. **Captain Jack 500 kV** (Dispatch one-line diagram No. 248548)		
Series Cap. Bank No. 1 (Captain Jack-Olinda line)	100	100
• MODs D#4974/8101, 4973/8099, 4975/8100	100	100
• Bypass breaker D#4971, 4972		
Grizzly No. 1 line terminal		
• Breaker D#4990	100	100
• Breaker D#4993	100	100
• MOD D#4989	100	100
• MOD D#4991/8104	100	100
• MOD D#4992	100	100
• MOD D#4994/8105	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Malin No. 1 line terminal		
• Breaker D#4996	100	100

	% BPA OWNED	% APPLICABLE TO PNW AC INTERTIE
• MOD D#4995	100	100
• MOD D#4997	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs	100	100
Olinda No. 1 line terminal		
• Breaker D#4977	100	100
• Breaker D#4980	100	100
• MOD D#4976	100	100
• MOD D#4978	100	100
• MOD D#4979	100	100
• MOD D#4981	100	100
• Associated Terminal Arresters	100	100
• Associated Line PTs (2 sets)	100	100
North Main Bus 500 kV PTs	100	100
South Main Bus 500 kV PTs	100	100
Station General		
15. **Chief Joseph Substation** (Dispatch one-line diagram No. 124313)		
230 kV, 1400 MW Braking Resistor	100	100
Includes breaker dispatch No. A-594, a high speed vacuum switch and one 230 kV isolating switch in Bay 12		
Station General		

1/ Station General will be allocated to each substation according to Bonneville's standard methodology.

2/ Each substation includes associated relays.

Capacity Owners

CAPACITY OWNER	CONTRACT NUMBER	CAPACITY OWNERSHIP SHARE (MW)	CAPACITY OWNERSHIP PERCENTAGE
PNGC	DE-MS79-94BP94523	50	1.4
Puget	DE-MS79-94BP94521	400	11.6
Seattle	DE-MS79-94BP94522	160	4.6
Snohomish	DE-MS79-94BP94525	42	1.2
Tacoma	DE-MS79-94BP94524	41	1.1

PNGC: Pacific Northwest Generating Cooperative
Puget: Puget Sound Power & Light Company
Seattle: City of Seattle, City Light Department
Snohomish: Public Utility District No. 1 of Snohomish County
Tacoma: Tacoma Public Utilities

Provisions Required by Statute or Executive Order

1. Contract Work Hours and Safety Standards Act (40 U.S.C. & 327, et seq.).

(a) Overtime Requirements.

Puget, contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall not require or permit any such laborers or mechanics in any workweek in which the individual is employed on such work to work in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than 1-1/2 times the basic rate of pay for all hours worked in excess of 40 hours in such workweek.

(b) Violation; liability for unpaid wages; liquidated damages.

In the event of any violation of the provisions set forth in section 1 of this Exhibit H, Puget and any subcontractor responsible therefore shall be liable for the unpaid wages. In addition, Puget and such subcontractor shall be liable to the United States for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions set forth in section 1 of this Agreement in the sum of $10.00 for each calendar day on which such individual was required or permitted to work in excess of the standard workweek of 40 hours without payment of the overtime wages required by provision set forth in section 1 of this Exhibit.

(c) Withholding for unpaid wages and liquidated damages.

The person designated in writing by Bonneville's Administrator with the Authority to enter into, administer, modify, suspend or terminate this Exhibit, make related determinations and findings and bind Bonneville only to the extent of delegated authority shall upon his or her own action or upon written request of an authorized representative of the Department of Labor withhold or cause to be withheld, from any moneys payable on account of work performed by Puget or its subcontractor, if any, under any such contract

or any other federal contract subject to the Contract Work Hours and Safety Standards Act which is held by the same prime contractor, such sums as may be determined to be necessary to satisfy any liabilities of Puget or such subcontractor for unpaid wages and liquidated damages as provided in section 2 of this Exhibit.

2. Convict Labor (Exec. Order No. 11755, Dec. 29, 1979).
In connection with the performance or work under this Agreement, Puget and any subcontractor, if any agrees not to employ any person undergoing sentence of imprisonment except as otherwise provided by law.

3. Equal Opportunity (Exec. Order No. 11246, Sep. 24, 1965).

(a) If , during any 12-month period (including the 12 months preceding the award of this contract), Puget has been or is awarded nonexempt federal contracts and/or subcontracts that have an aggregate value in excess of $25,000.00, Puget shall comply with sections 3(b)(1) through 3(b)(11) below. Upon request, Puget shall provide information necessary to determine the applicability of this clause.

(b) During performance of this Agreement, Puget agrees as follows:

(1) Puget shall not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin.

(2) Puget shall take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to: (1) employment; (2) upgrading; (3) demotion; (4) transfer; (5) recruitment or recruitment advertising; (6) layoff or termination; (7) rates of pay or other forms of compensation; and (8) selection for training, including apprenticeship.

(3) Puget shall post in conspicuous places, available to employees and applicants for employment, the notices that explain this clause, such notices to be provided by the person designated in writing by Bonneville's Administrator with the authority to enter into, administer, modify, suspend or terminate this Agreement, make related determinations and findings and bind Bonneville only to the extent of delegated authority (Contracting Officer).

(4) Puget shall, in all solicitations or advertisements for employees placed by or on behalf of Puget, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(5) Puget shall send, to each labor union or representative or of workers with which it has a collective bargaining agreement or other contract or understanding, the notice provided by the Contracting Officer advising the labor union or workers' representative of Puget's commitments under this clause, and post copies of the notice in conspicuous places available to employees and applicants for employment.

(6) Puget shall comply with Executive Order No. 11246, Sep. 24, 1965 (30 Fed. Reg. 12319), as amended, and the rules, regulations and orders of the Secretary of Labor.

(7) Puget shall furnish to Bonneville all information required by Executive Order No. 11246, as amended, and by the rules, regulations and orders of the Secretary of Labor. Standard Form 100 (EEO-1), or any successor form, is the prescribed form to be filed within 30 days following the award of this contract, unless filed within 12 months preceding the date of the award of this contract.

(8) Puget shall permit access to its books, records and accounts by Bonneville or the Office of Federal Contract Compliance Programs

(OFCCP) for purpose of investigation to ascertain Puget's compliance with such rules, regulations and orders.

(9) If the OFCCP determines that Puget is not in compliance with this clause or any rule, regulation or order of the Secretary of Labor, this Agreement may be canceled, terminated, or suspended in whole or in part and Puget may be declared ineligible for further Government contracts, under the procedures authorized in Executive Order No. 11246, as amended. In addition, sanctions may be imposed and remedies invoked against Puget as provided in Executive Order No. 11246, as amended, the rules, regulations and orders of the Secretary of Labor, or as otherwise provided by law.

(10) Puget shall include the terms and conditions of sections 3(b)(1) through 3(b)(11) of this Exhibit in every subcontract or purchase order that is not exempted by the rules, regulations, or orders of the Secretary of Labor issued under Executive Order No. 11246, as amended, so that these terms and conditions will be binding upon each subcontractor or vendor.

(11) Puget shall take such action with respect to any subcontract or purchase order as may direct as means of enforcing these terms and conditions, including sanctions for noncompliance: Provided, that if Puget becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of any direction, Puget may request the Government to enter into the litigation to protect the interest of the United States.

(c) Notwithstanding any other clause in this Agreement, disputes relative to this clause will be governed by the procedures in 41 CFR § 66-1.1.

4. Certification of Non-segregated Facilities (48 CFR § 22.810).

(a) Puget certifies that it does not and will not maintain or provide for employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. Puget agrees that a breach of this certification is a violation of section 3 (the Equal Opportunities Clause) of this Exhibit.

(b) Puget agrees that it will (1) obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000.00 which are not exempt from the provisions of the Equal Opportunity Clause; (2) retain such certifications in its files (3) forward the following notice to such proposed subcontractors, except where the proposed subcontractors have submitted identical certifications of specific time periods:

> "Notice to Prospective Subcontractors of Requirement for Certifications of Non-segregated Facilities.
>
> "A Certification of Non-segregated Facilities must be submitted prior to the award of a subcontract under which the subcontractor will be subject to the Equal Opportunity clause. This certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually or annually)."

5. Officials Not to Benefit (41 U.S.C. § 22).

No member of or delegate to Congress, or resident commissioner, shall be admitted to any share or part of this Agreement or to any benefit arising from it. However, this clause does not apply to this Agreement to the extent that this Agreement is made with a corporation for the corporation's general benefit.

6. Bonneville's Obligations Not General Obligations of the United States (16 U.S.C. § 839(j)).

None of the offerings of obligations, or promotional materials for such obligations, which may be offered by Puget to fund its activities pursuant to

this Agreement, shall be construed to be, general obligations of the United States, nor are such obligations intended to be or are they secured by the full faith and credit of the United States.

7. Small Business Act (15 U.S.C. §§ 631 and 637).

(a) It is the policy of the Government that small business concerns owned and controlled by socially and economically disadvantaged individuals shall have the maximum practicable opportunity to participate in the performance of contracts let by any federal agency.

(b) Puget hereby agrees to carry out the policy set forth in 7(a) in awarding subcontracts to the fullest extent consistent with the efficient performance of this Agreement. Puget further agrees to cooperate on any studies or surveys as may be conducted by the United States Small Business Administration or Bonneville as may be necessary to determine the extent of Puget's compliance with this clause.

(c) As used in this agreement the term "small business concern" shall mean a small business as defined in section 3 of Small Business Act (15 U.S.C. § 632) and relevant regulations promulgated pursuant thereto. The term "small business concern owned and controlled by socially and economically disadvantaged individuals" shall mean a small business concern:

(1) which is at least 51 percent owned by one or more socially disadvantaged individuals; or, in the case of any publicly owned business, at least 51 percent of the stock of which is owned by one or more socially or economically disadvantaged individuals; and

(2) whose management and daily business operations are controlled by one or more such individuals.

Puget shall presume that socially and economically disadvantaged individuals include Black Americans, Hispanic Americans, Native Americans, Asian Pacific Americans and other minorities, or any other individual found to be disadvantaged by the United States Small Business Administration pursuant to section 8(a) of the Small Business Act.

(d) Puget acting in good faith may rely on written representations by its subcontractor regarding its status as either a small business concern or a small business concern owned and controlled by socially and economically disadvantaged individuals.

8. Other Statutes, Executive Orders and Regulations.

(a) Puget agrees to comply with the following statutes, executive orders and regulations to the extent applicable:

(1) False Claims Act, 31 U.S.C. § 3729, et seq. Whoever makes or presents to any person or officer in the civil military or naval service of the United States, or to any department or agency thereof, any claim upon or against the United States, or any department or agency thereof, knowing such claim to be false, fictitious or fraudulent, shall be fined not more than $10,000.00 or imprisoned not more than 5 years, or both;

(2) Rehabilitation Act of 1973, 29 U.S.C. §793, as amended, Executive Order No. 11758, Jan. 15, 1974, and the regulations of the Secretary of Labor, 41 CFR Part 60-250, et seq., which concern affirmative action for handicapped workers;

(3) Vietnam Era Veterans Readjustment Assistance Act of 1972, 38 U.S.C. §§ 101, 102, 240, 241, 1502, 1504, 1507, as amended, and the clauses contained in 41 CFR Part 60-250, et

seq., which concern affirmative action for disabled veterans and veterans of the Vietnam Era;

(4) Executive Order No. 11625, Oct. 13, 1971, and implementing regulations which concern utilization of small disadvantaged business concerns;

(5) Anti-Kickback Act, 41 U.S.C. § 51, et seq.; and

(6) Privacy Act of 1974, 5 U.S.C. § 552a.

(b) Puget agrees to comply with requirements deemed necessary by Bonneville in order to implement Bonneville's obligations under the National Historic Preservation Act of 1966, U.S.C. §§ 470, et seq.

Bonneville's PNW AC Intertie Costs

All costs in sections I through VIII of this Exhibit I shall be subject to the following provisions:

PURPOSE

Bonneville shall determine and calculate Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, Power Scheduling Costs, and End of Term Costs with respect to Bonneville's PNW AC Intertie in accordance with this Exhibit I. None of Operations Costs, Maintenance Costs, Replacement Costs and Reinforcement Costs, General Plant Costs, Other Costs, Contracts and Rates Costs, and End of Term Costs (each of the foregoing for purposes of this sentence, a Cost) shall include any other Cost.

SOURCE OF INFORMATION AND COSTS

Bonneville shall forecast in accordance with this Exhibit I the costs reflected in any Operating Plan pursuant to Schedules A through H of this Exhibit using the most detailed information available to Bonneville from its budget process at the time the forecast is made. Bonneville shall determine the actual costs reflected in any Operating Plan pursuant to Schedules A through H, using Bonneville's then existing accounting system in accordance with this Exhibit I. All costs reflected in Schedules A through H shall be net of credit.

Bonneville shall determine its overall overhead and overall indirect costs. A portion of Bonneville's overall overhead and indirect costs shall be allocated to such total system operations costs (pursuant to section I below), total system maintenance costs (pursuant to section II below), total capital costs (pursuant to sections III and IV below), Other Costs (pursuant to section V below), Contracts and Rates Costs (pursuant to section VI below), Power Scheduling Costs (pursuant to section VII below), and End of Term Costs (pursuant to section VIII below) using Bonneville's

normal allocation or distribution methodologies for such costs, as such methodologies may be changed by Bonneville from time to time. Such allocations or distribution methodologies shall not be required to meet any stricter standard of benefit to Bonneville's PNW AC Intertie than with respect to other transmission facilities.

Bonneville shall record its costs into its accounting systems in accordance with generally accepted accounting principles. For purposes of this Agreement, "generally accepted accounting principles" means the common set of accounting concepts, standards, and procedures that are adopted by entities (such as the utility industry) for purposes of financial statement disclosure.

Whenever Bonneville alters its accounting system or methods to permit costs referred to in this Exhibit I, which were previously allocated to functions and activities, to be directly assigned to function and activities, then in that event Puget and Bonneville shall, in concert with the Capacity Owners other than Puget, in good faith negotiate revisions to this Exhibit I to include such directly assigned costs.

COSTS

I. Operations Costs

A. Operations Costs - Allocation Factor

The allocation factor (Schedule A, line 3) used to determine the Allocated Direct Cost of Operations Cost, Indirect Cost of Operations Cost, and Overhead Cost of Operations Cost is the ratio of major facility units (MFUs) of Bonneville's PNW AC Intertie operated by Bonneville to MFUs of the Federal Columbia River Transmission System.

An MFU (Schedule A, lines 1 and 2) is any of the following major pieces of power system equipment which, at any given time, is installed on and is a part of the Federal Columbia River Transmission System: substation switchgear (such as power circuit breakers; potential devices; disconnects, load interrupters, hot-stick operated bus links; switching devices, circuit switchers, ground switches; and switchyard equipment terminals); protective equipment (such as grounding devices; reactors; arrestors and resistors;

voltage regulators; engine generators and motor generators; and high voltage fuses); transformation equipment (such as power transformers; diesel generators; grounding transformers; regulators and shunt reactors; synchronous condensers; and shunt or series capacitors); station equipment (such as switchyard lighting, batteries and chargers, air compressors, station service equipment, and lightening arrestors); instruments, control, and supervisory equipment (such as switchboards, instruments, and control panels; relay panels, transfer trip, and single-pole relaying; and oscillographs; fault detectors and locators; sequential events recorders, supervisory control, and data acquisition equipment; and indicating meters, instruments, and loggers); and equipment specific to direct current and static var compensator stations (such as mercury arc valves; thyristor systems; air handling packages; water control packages; harmonic filtering systems; motor control centers, such as fans, pumps, and dampening resistors; and valve damping resistors); or devices that perform similar types of functions.

Once each fiscal year, Bonneville shall count the number of MFUs on Bonneville's PNW AC Intertie (exclusive of facilities operated by others) (Schedule A, line 1) and the number of MFUs on the Federal Columbia River Transmission System (Schedule A, line 2). In calculating the forecast Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs, Bonneville shall use the most recent MFU count available at the time of such calculation in developing its initial Operating Plan for a given fiscal year. For each Operating Plan which is for the same fiscal year, Bonneville shall use the same MFU count in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

B. Operations Costs - Operations Functionalization Factor

For each Operating Plan, Bonneville's total system operations direct cost, indirect cost and overhead cost (Schedule A, lines 7, 9, and 11) shall be adjusted by an operations functionalization factor (Schedule A, line 6) so that Capacity Owners pay only transmission-related system operations costs. The

operations functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using the costs developed for the last year of the rate period for which Bonneville has developed rates, the operations functionalization factor shall be the ratio of (a) Bonneville's total system operations cost functionalized to transmission (Schedule A, line 4) over (b) Bonneville's total system operations cost (Schedule A, line 5). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Allocated Direct Cost, Indirect Cost, and Overhead Cost components of Operations Costs.

C. Operations Costs - Allocated Direct Costs

For each Operating Plan, Bonneville shall allocate its total system operations direct costs as set forth in Schedule A, lines 7 and 8, to determine Allocated Direct Costs of Operations Cost (Schedule A, line 8).

Schedule A, line 7, shall reflect Bonneville's total system operations direct costs for a fiscal year. Bonneville's total system operations direct costs for a fiscal year shall include all system operations expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: substation operations (which provides for, among other things, making equipment adjustments to maintain loads and voltages within acceptable limits, switching to deenergize lines and equipment during maintenance outages, isolating damaged equipment, restoring service to customers, visually inspecting equipment, and reading meters that record line and equipment loading and voltages), power system control and dispatching (which provides for, among other things, central dispatching, control, and monitoring of the electric operation of the Federal transmission system; load, frequency, and voltage control of

Federal generating plants; the operating of the system control and data computers at the Dittmer and Eastern Control Centers; and modification and maintenance of the operation-related computers), and operations standards and engineering (which provides for, among other things, analyzing system loads, voltage levels, outage information, stability levels, and other data; making policy recommendations for system operations; planning operations' practices, restoration plans and disturbance ports; development of control center requirements for centralized automation of substations and generation; and Bonneville's participation with other utilities in developing utility operating standards and guides); and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 8, shall reflect Allocated Direct Cost of Operations Cost.

D. Operations Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system operations indirect costs as set forth in Schedule A, lines 9 and 10, to determine Indirect Costs of Operations Costs.

Schedule A, line 9, shall reflect Bonneville's total system operations indirect costs for a fiscal year. Bonneville's total system operations indirect costs for a fiscal year shall include all system operations indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities: general supervision and management, office support, planning, budgeting, training, direction of facilities' operation, and other system operations activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed

activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A, line 10, shall reflect Indirect Cost of Operations Cost.

E. Operations Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system operations overhead costs as set forth in Schedule A, lines 11 and 12, to determine Overhead Costs of Operations Costs.

Schedule A, line 11, shall reflect Bonneville's total system operations overhead costs for a fiscal year. Bonneville's total system operations overhead costs for a fiscal year shall include all system operations overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system operations overhead activities undertaken by Bonneville that are consistent with system operations activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule A, line 12, shall reflect Overhead Cost of Operations Cost.

Schedule A, line 13, shall reflect Operations Cost.

II. Maintenance Costs

A. Maintenance Costs - Power System Control Maintenance Functionalization Factor

For each Operating Plan, the Power System Control (PSC) maintenance cost (Schedule B, line 4) shall be adjusted by a PSC maintenance functionalization factor (Schedule B, line 3). PSC maintenance is the testing, repair, and engineering support for Bonneville's communications and control systems. The PSC maintenance functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs for the last year of the rate period for which Bonneville has developed rates, the PSC functionalization factor shall be the ratio of (a) Bonneville's total PSC maintenance cost functionalized to transmission from such general rate case (Schedule B, line 1) over (b) Bonneville's total PSC maintenance cost from such general rate case (Schedule B, line 2).

B. Maintenance Costs - Direct Costs

The Direct Costs of Maintenance Costs for a fiscal year (Schedule B, line 7) shall be Bonneville's direct costs of maintaining Bonneville's PNW AC Intertie and shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following activities for maintenance of Bonneville's PNW AC Intertie: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; pollution control and

abatement; and other system maintenance activities related to preventive and corrective maintenance of Bonneville's PNW AC Intertie undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

With the exception of PSC maintenance costs, Bonneville shall specifically identify the direct costs of maintaining Bonneville's PNW AC Intertie (Schedule B, line 7). To determine PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6), the total PSC direct maintenance cost (Schedule B, line 4) shall be multiplied by (a) the PSC maintenance functionalization factor (Schedule B, line 3) and (b) the MFU allocation factor (Schedule B, line 5) set forth in Schedule A, line 3. The Direct Costs of Maintenance Costs (Schedule B, line 8) shall be the sum of (a) PSC direct maintenance cost for Bonneville's PNW AC Intertie (Schedule B, line 6) and (b) the direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost (Schedule B, line 7).

C. Maintenance Costs - Allocation Factor

The allocation factor (Schedule B, line 10) used to determine Indirect Cost of Maintenance Cost and Overhead Cost of Maintenance Cost shall be the ratio of the Direct Cost of Maintenance Cost (Schedule B, line 8) to Bonneville's total system maintenance direct cost (Schedule B, line 9), as described below.

Schedule B, line 9, shall reflect Bonneville's total system maintenance direct costs for a fiscal year. Bonneville's total system maintenance direct costs for a fiscal year shall include all maintenance expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of any of the following

activities: transmission line maintenance; substation maintenance; power system control maintenance; nonelectric plant maintenance; establishing, monitoring, and updating system maintenance standards, policies, and procedures; pollution control and abatement; and other system maintenance activities related to preventive and corrective maintenance of the Federal Columbia River Transmission System undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 10, shall reflect the percentage which shall be used to allocate Bonneville's total system maintenance indirect cost and total system maintenance overhead cost to Bonneville's PNW AC Intertie.

D. Maintenance Costs - Indirect Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance indirect costs as set forth in Schedule B, lines 11 and 12, to determine Indirect Costs of Maintenance Costs.

Schedule B, line 11, shall reflect Bonneville's total system maintenance indirect costs for a fiscal year. Bonneville's total system maintenance indirect costs for a fiscal year shall include all system maintenance indirect expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance any of the following activities: supervision and management, office support, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other system maintenance activities undertaken by Bonneville that are consistent with system maintenance

activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule B, line 12, shall reflect Indirect Cost of Maintenance Cost.

E. Maintenance Costs - Overhead Costs

For each Operating Plan, Bonneville shall allocate its total system maintenance overhead costs as set forth in Schedule B, lines 13 and 14, to determine Overhead Costs of Maintenance Costs.

Schedule B, line 13, shall reflect Bonneville's total system maintenance overhead costs for a fiscal year. Bonneville's total system maintenance overhead costs for a fiscal year shall include all system maintenance overhead expenses for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other expenses, each of which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering); and (c) other system maintenance overhead activities undertaken by Bonneville that are consistent with system maintenance activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

Schedule B, line 14, shall reflect Overhead Cost of Maintenance Cost.

Schedule B, line 15, shall reflect Maintenance Cost.

III. Replacement Costs and Reinforcement Costs

A. Replacement Costs and Reinforcement Costs - Direct Costs

The Direct Costs for Replacements and Reinforcements for a fiscal year (Schedule C, line 1) shall be Bonneville's direct capital costs for Replacements and Reinforcements for such fiscal year and shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, land, materials and equipment, spare parts, administration of spare parts, transportation of spare parts, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of the following activities: planning, environmental analyses and mitigation, survey, design, land, materials and equipment, turnkey contracts, contract construction, force account construction, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council. The Direct Costs for any Replacement or Reinforcement for a fiscal year shall also include the costs of removal and any salvage credits with respect to any PNW AC Intertie facility removed on account of such Replacement or Reinforcement.

B. Replacement Costs and Reinforcement Costs - Indirect Costs and Overhead Costs

For each Replacement and Reinforcement project, the Indirect Costs and Overhead Costs for Replacements and Reinforcements (Schedule C, line 2) shall be allocated or distributed to such Replacements and Reinforcements using the indirect and overhead allocation and distribution methodologies employed by Bonneville to allocate and distribute indirect and overhead costs

to all of Bonneville's other capital projects during the time the Replacements and Reinforcements are under construction. Schedule C, line 2, shall reflect the Indirect Costs and Overhead Costs of Replacements and Reinforcements.

Indirect Costs of Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel expenses, service contracts, consulting contracts, administration of materials, tools, tools procurement and administration, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: supervision, technical analyses, engineering studies, program analyses, planning, budgeting, training, and other reinforcement and replacement activities undertaken by Bonneville that are consistent with reinforcement and replacement activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Overhead Costs for Replacements and Reinforcements shall include all costs for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, and other costs, each of which being which being incurred by Bonneville in connection with any of the following activities and services of Bonneville: (a) support services (including services with respect to mainframe computers, microcomputers, laboratories, building management, materials and procurement, Electric Power Research Institute, fixed-wing aircraft, helicopter, tools, and work equipment); (b) general and administrative activities (including general and administrative activities with respect to the office of the Administrator, the Washington DC office, and the offices of: contracts and property management; fish and wildlife; equal employment opportunity; information resources; environment; internal audit; external affairs; general counsel; quality improvement; planning council liaison; financial management; power sales; energy resources; management services; area offices; operations, maintenance, and construction; and engineering);

and (c) other replacement and reinforcement activities undertaken by Bonneville that are consistent with replacement and reinforcement activities similar to the above-listed activities undertaken by utilities in the Western System Coordinating Council.

C. Replacement Costs and Reinforcement Costs - Allowance for Funds Used During Construction (AFUDC)

Schedule C, line 3, shall reflect AFUDC for Replacements and Reinforcements. At the beginning of each fiscal year, Bonneville shall calculate the AFUDC rate for such fiscal year. Bonneville shall apply such AFUDC rate monthly to the costs in accounts for construction work in progress for Replacements and Reinforcements.

D. Replacement Costs and Reinforcement Costs - Interest

Schedule C, line 4, shall reflect the interest cost payable by Puget pursuant to this Agreement with respect to any Replacement or Reinforcement. Such interest cost for any Replacement or any Reinforcement shall be simple interest calculated at a rate equal to the weighted average interest rate on Bonneville's then outstanding bonds or other debt instruments and such interest shall accrue from the date Bonneville stops accruing AFUDC (approximately the date the work order for such Replacement or such Reinforcement is closed) with respect to such Replacement or such Reinforcement to the due date of the monthly power bill containing the charge for such Replacement or such Reinforcement.

IV. General Plant Costs

For each Operating Plan, Bonneville shall adjust, amortize, and allocate Bonneville's total general plant investment (as described below) and Bonneville's Dittmer control equipment investment as set forth in Schedule D, lines 1 through 11, to determine General Plant Cost.

Schedule D, line 1, shall reflect for a fiscal year Bonneville's total cumulative general plant investment. Bonneville's total general plant investment shall

include Bonneville's investments in any of the following: land-general plant, structures/improvements-general plant, office furniture and equipment, transportation equipment, stores equipment, tools/shop/garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment (including equipment or apparatus used in Bonneville's utility operations which are not includable in any other general plant investment category), and other similar investment made by Bonneville that is consistent with general plant investment made by utilities in the Western Systems Coordinating Council.

Schedule D, line 2, shall reflect for a fiscal year Bonneville's cumulative investment in Dittmer control equipment.

Schedule D, line 3, shall reflect Bonneville's total general plant investment and Bonneville's Dittmer control equipment investment functionalized to generation using the methodology for functionalizing general plant as set forth in Bonneville's general rate case most recently approved by FERC on an interim basis.

Schedule D, line 4, shall reflect any general plant investment recovered from all Capacity Owners under the CO-94 rate as such general plant investment is unitized by Bonneville; provided, however, for the first two Operating Plans Bonneville shall estimate the amount of the general plant investment included in the Initial Capacity Ownership Price, which estimate shall be reflected in Schedule D, line 4, and Bonneville shall modify such Operating Plans by December 1995, or as soon as practicable thereafter, to reflect in Schedule D, line 4, the actual general plant investment included in the Adjusted Capacity Ownership Price.

Schedule D, line 5, shall reflect any general plant investment recovered from Capacity Owners pursuant to section 5 for Upgrades. The agreements referred to in subsection 5(d) and subparagraph 5(e)(3)(B) shall specify the

portion of costs of an Upgrade that will be considered general plant investment.

Schedule D, line 6, shall reflect Bonneville's adjusted general plant investment functionalized to transmission and shall be calculated by adding line 1 and line 2, and from the sum of line 1 and line 2 subtracting line 3, line 4, and line 5.

Schedule D, line 7, shall reflect Bonneville's annual cost of Bonneville's adjusted general plant investment functionalized to transmission (Schedule D, line 6). Such annual cost shall be the sum of the annual interest and amortization amounts for each category of adjusted general plant investment. The annual interest and amortization amounts for each category shall be calculated by using the investment amounts for each such category, the weighted average interest rate for all Bonneville then outstanding bonds, and the average service lives for each such category from Bonneville's most recent depreciation study. If Bonneville changes its practice of financing general plant investment with bonds, the interest rate used in the calculation referred to in the immediately preceding sentence shall reflect the weighted average interest rate for all of Bonneville's then outstanding debt instruments.

Schedule D, line 8, shall reflect for a fiscal year Bonneville's total cumulative transmission plant-in-service investment (not including general plant investment). Bonneville's total transmission plant-in-service investment shall include Bonneville's investment in any of the following items reflected as total transmission plant-in-service (not including general plant investment) in the Segmentation Study (from Bonneville's general rate case most recently approved by FERC on an interim basis: land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant

investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

Schedule D, line 9, shall be the annual cost ratio of Bonneville's PNW AC Intertie transmission-related general plant derived by dividing Schedule D, line 7, by Schedule D, line 8.

Schedule D, line 10, shall reflect Bonneville's PNW AC Intertie investment. Bonneville's PNW AC Intertie investment shall include Bonneville's investment in any of the following items reflected as Bonneville's PNW AC Intertie plant-in-service in the Segmentation Study from Bonneville's general rate case most recently approved by FERC on an interim basis (or the successor to the Segmentation Study, as determined by Bonneville): land and land rights-transmission plant, structures/improvements-transmission plant, station equipment, towers and fixtures, poles and fixtures, overhead conductor, underground conductor, roads and trails, and other transmission plant investment made by Bonneville that is consistent with transmission plant investments made by utilities in the Western Systems Coordinating Council.

V. Other Costs

For each Operating Plan, Bonneville shall include Other Costs associated with Bonneville's PNW AC Intertie for a fiscal year. Such Other Costs (Schedule E, line 3) for a fiscal year shall include for such fiscal year any of the following: (1) the costs of operation; maintenance; capital replacements, reinforcements, additions, betterments, renewals; or related costs which Bonneville is obligated to pay pursuant to the Northwest Intertie Agreements or other contracts referred to in subsection 8(b) of this Agreement; and (2) costs paid by Bonneville including monetary judgments, settlements, binding awards, non-contract penalties, contract penalties, liquidated damages, or forfeiture costs, and Bonneville's costs related to such monetary judgments, settlements, binding awards, non-contract penalties, contract penalties,

liquidated damages, or forfeiture costs assessed against or incurred by Bonneville as a facilities owner of, or the operator of, the PNW AC Intertie; provided, however, that Puget shall not be obligated to pay a share of any such costs that are not properly allocated to Bonneville's PNW AC Intertie.

Bonneville shall forecast its share of operations, maintenance, capital, and related costs for activities that PacifiCorp performs on Bonneville/PacifiCorp jointly-owned PNW AC Intertie facilities based on forecasts received from PacifiCorp or on actual costs for the most recent 12 consecutive month period prior to preparation of an Operating Plan.

VI. Contracts and Rates Costs

A. Contracts and Rates Costs - Functionalization Factor

For each Operating Plan, Bonneville's total contracts and rates direct costs, indirect costs, and overhead costs (Schedule F, lines 5, 6, and 7) shall be adjusted by a contracts and rates functionalization factor (Schedule F, line 3). The contracts and rates functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the contracts and rates functionalization factor shall be the ratio of (a) Bonneville's total transmission-related contracts and rates cost (Schedule F, line 1) over (b) Bonneville's total contracts and rates cost (Schedule F, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Contracts and Rates Cost.

B. Contracts and Rates Costs - Allocation Factor

The allocation factor (Schedule F, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Contracts and Rates Costs - Total Contracts and Rates Costs

Bonneville's total contracts and rates costs for a fiscal year (Schedule F, line 8) shall include Bonneville's expenses (including direct, indirect, and

overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: rate filings with FERC, development of rates customers pay Bonneville for electric power and for wheeling their own power on Bonneville's transmission system; negotiation, administration, and coordination of contracts for power sales, power exchanges, conservation, wheeling and resource services; and analyzing, processing, and issuing all customer power bills; and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule F, line 9, shall reflect Contracts and Rates Cost.

VII. Power Scheduling Costs

For each Operating Plan, Bonneville's total power scheduling direct costs, indirect costs, and overhead costs (Schedule G, lines 5, 6, and 7) shall be adjusted by a power scheduling functionalization factor (Schedule G, line 3). The power scheduling functionalization factor shall be based on a ratio of costs from Bonneville's general rate case most recently approved by FERC on an interim basis. Using costs developed for the last year of the rate period for which Bonneville has developed rates, the power scheduling functionalization factor shall be the ratio of (a) Bonneville's total transmission-related power scheduling cost (Schedule G, line 1) over (b) Bonneville's total power scheduling cost (Schedule G, line 2). For each Operating Plan, Bonneville shall use the same functionalization factor in calculating the forecast and actual Power Scheduling Cost.

B. Power Scheduling Costs - Allocation Factor

The allocation factor (Schedule G, line 4) shall be the allocation factor established in Schedule A, line 3.

C. Power Scheduling Costs - Total Power Scheduling Costs

Bonneville's total power scheduling costs for a fiscal year (Schedule G, line 8) shall include Bonneville's expenses (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, tools, and direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other expenses, each of which being incurred by Bonneville in connection with the performance of the following activities: scheduling and marketing power to Bonneville customers and interconnected utilities, forecasting the hourly power requirements of Bonneville customers and the interchange of power with the region's interconnected electric utilities and with utilities outside the region, scheduling power to be generated at each Federal plant, weather and streamflow forecasting, controlling the reservoirs, implementing the intertie access policy, coordinating power production with the multi-purpose operation of the Federal power system, seasonal load/resource planning, developing current short-term operating plans, short-term marketing of Bonneville's surplus firm power, exchanges, and nonfirm energy, and other activities undertaken by Bonneville that are consistent with activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule G, line 9, shall reflect Power Scheduling Cost.

VIII. End of Term Costs

When all facilities of the PNW AC Intertie are determined, in accordance with Northwest Intertie Agreements, to be no longer operable, Bonneville shall include a forecast of all Bonneville's costs associated with

decommissioning the PNW AC Intertie and credits resulting from such decommissioning in the Operating Plan for each fiscal year that such End of Term Costs are to be incurred. Bonneville's End of Term Costs for a fiscal year (Schedule H, line 4) shall include Bonneville's costs (including direct, indirect, and overhead costs) for such fiscal year for any of the following: salaries, wages, employee benefits, overtime pay, travel, service contracts, consulting contracts, materials, spare parts, transportation of spare parts, tools, direct support services (including equipment use activities, general shops activities, and heavy mobile equipment maintenance), and other costs, each of which being incurred by Bonneville in connection with the performance of any of the following activities: decommissioning, razing structures, disposal of debris, site restoration, meeting all requirements of Federal, state, or local applicable law relating to the foregoing activities, and other decommissioning activities undertaken by Bonneville that are consistent with decommissioning activities similar to the above-listed activities undertaken by utilities in the Western Systems Coordinating Council.

Schedule A for FY XXXX

	Line No.	Forecast	Actual	Difference
I. Operations Costs				
A. Allocation Factor				
MFUs of Bonneville's PNW AC Intertie	1		_____	
MFUs of the FCRTS	2		_____	
Allocation factor (Line 1/Line 2)	3		_____	
B. Operations Functionalization Factor				
Bonneville's total transmission-related systems operations cost from rate case	4		_____	
Bonneville's total system operations cost from rate case	5		_____	
Operations functionalization factor (Line 4/Line 5)	6		_____	
C. Allocated Direct Cost				
Bonneville's total system operations direct cost	7	_____	_____	_____
Allocated Direct Cost of Operations Cost (Line 3 * Line 6 * Line 7)	8	_____	_____	_____

	Line No.	Forecast	Actual	Difference
D. Indirect Cost				
Bonneville's total system operations indirect cost	9	_____	_____	_____
Indirect Cost of Operations Cost (Line 3 * Line 6 * Line 9)	10	_____	_____	_____
E. Overhead Cost				
Bonneville's total system operations overhead cost	11	_____	_____	_____
Overhead Cost of Operations Cost (Line 3 * Line 6 * Line 11)	12	_____	_____	_____
F. Operations Cost (Lines 8 + 10 + 12)	13	_____	_____	_____

Schedule B for FY XXXX

	Line No.	Forecast	Actual	Difference
II. Maintenance Cost				
A. Power System Control (PSC) Maintenance Functionalization Factor				
Bonneville's transmission-related PSC maintenance cost from rate case	1		_____	
Bonneville's total PSC maintenance cost from rate case	2		_____	
PSC maintenance functionalization factor (Line 1/Line 2)	3		_____	
B. Direct Cost				
Total PSC direct maintenance cost	4	_____	_____	_____
MFU Allocation Factor (Schedule A, line 3)	5		_____	
PSC direct maintenance cost for Bonneville's PNW AC Intertie (Line 4 * Line 3 * Line 5)	6	_____	_____	_____
Bonneville's direct cost of maintaining Bonneville's PNW AC Intertie excluding PSC maintenance cost	7	_____	_____	_____
Direct Cost of Maintenance Cost (Line 6 + Line 7)	8	_____	_____	_____

C. Allocation Factor

Bonneville's total system maintenance direct cost	9			
Allocation factor for Indirect Cost and Overhead Cost (Line 8/Line 9)	10			

D. Indirect Cost

Bonneville's total system maintenance indirect cost	11			
Indirect Cost of Maintenance Cost (Line 11 * Line 10)	12			

E. Overhead Cost

Bonneville's total system maintenance overhead cost	13			
Overhead Cost of Maintenance Cost (Line 13 * Line 10)	14			
F. Maintenance Cost (Lines 8 + 12 + 14)	15			

Schedule C

	Line No.	Forecast	Actual	Difference
III. Replacement Costs and Reinforcement Costs				
A. Direct Cost				
Direct Costs of Replacements and Reinforcements	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of Replacements and Reinforcements	2	_____	_____	_____
C. AFUDC				
AFUDC of Replacements and Reinforcements	3	_____	_____	_____
D. Interest				
Interest Cost of Replacements and Reinforcements	4		_____	
E. Total Replacement Costs and Reinforcement Costs (Lines 1 + 2 + 3 + 4)	5	_____	_____	_____

Notes:

A separate Schedule C will be provided in the Operating Plan for each Replacement and Reinforcement.

Forecasts of Replacement Costs and Reinforcement Costs will be provided; Capacity Owners shall be billed for Replacements and Reinforcements using actual cost pursuant to section 9(b)(2)(B).

Schedule D for FY XXXX

	Line No.	Allocated Actual
IV. General Plant Cost		
Bonneville's total general plant investment	1	_____
Bonneville's Dittmer control equipment investment	2	_____
General plant investment of lines 1 and 2 functionalized to generation	3	_____
General plant investment recovered from all Capacity Owners in Adjusted Capacity Ownership Price and Revised Adjusted Capacity Ownership Price	4	_____
General plant investment recovered from Capacity Owners for Upgrades	5	_____
Adjusted general plant investment functionalized to transmission (Line 1 + Line 2 - Line 3 - Line 4 - Line 5)	6	_____
BPA total annual cost of Line 6 general plant investment	7	_____
BPA total transmission plant-in-service investment (not including general plant investment) from Segmentation Study	8	_____
ACR for Bonneville's PNW AC Intertie (Line 7/Line 8)	9	_____
Bonneville's PNW AC Intertie investment from Segmentation Study	10	_____
General Plant Cost (Line 9 * Line 10)	11	_____

Schedule E for FY XXXX

	Line No.	Forecast	Actual	Difference
V. Other Costs				
A. PacifiCorp and related costs	1	_____	_____	_____
B. Other PNW AC Intertie costs	2	_____	_____	_____
C. Total Other Costs	3	_____	_____	_____

Schedule F for FY XXXX

	Line No.	Forecast	Actual	Difference
VI. Contracts and Rates Costs				
A. Contracts and Rates Functionalization Factor				
Transmission-related contracts and rates cost from rate case	1		_____	
Total contracts and rates cost from rate case	2		_____	
Contracts and rates cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Contracts and Rates Costs				
Contracts and rates direct costs	5	_____	_____	_____
Contracts and rates indirect costs	6	_____	_____	_____
Contracts and rates overhead costs	7	_____	_____	_____
Bonneville's total contracts and rates costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Contracts and Rates Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule G for FY XXXX

	Line No.	Forecast	Actual	Difference
VII. Power Scheduling Costs				
A. Power Scheduling Functionalization Factor				
Transmission-related power scheduling costs from rate case	1		_____	
Total power scheduling cost from rate case	2		_____	
Power scheduling cost functionalization factor (Line 1/Line 2)	3		_____	
B. Allocation Factor				
MFU allocation factor (Schedule A, line 3)	4		_____	
C. Total Power Scheduling Costs				
Power scheduling direct costs	5	_____	_____	_____
Power scheduling indirect costs	6	_____	_____	_____
Power scheduling overhead costs	7	_____	_____	_____
Bonneville's total power scheduling costs (Line 5 + Line 6 + Line 7)	8	_____	_____	_____
D. Power Scheduling Cost (Line 8 * Line 3 * Line 4)	9	_____	_____	_____

Schedule H for FY XXXX

	Line No.	Forecast	Actual	Difference
VIII. End of Term Costs				
A. Direct Cost				
Direct Cost of End of Term Costs	1	_____	_____	_____
B. Indirect Costs and Overhead Costs				
Indirect Costs and Overhead Costs of End of Term Costs	2	_____	_____	_____
C. Credits				
Credits from decommissioning PNW AC Intertie facilities	3	(_____)	(_____)	(_____)
D. End of Term Costs	4	_____	_____	_____

Puget's Initial Transaction with California Utility

Name of parties: Puget / Pacific Gas & Electric Company

Term of Contract: Variable

Date of Execution: October 25, 1991

Amount of Transaction (MW): 300 MW

DC NOB S>N 2005

Customer	Contract Number	MW
Bonneville Power Administration, Power Business Line	96MS-95363	100
Bonneville Power Administration, Power Business Line	96MS-95363	100
PacifiCorp (FPT)	DE-MS79-94BP94280	200

SALE AND EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF PASADENA

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This SALE AND EXCHANGE AGREEMENT, executed as of _____, 19__, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF PASADENA, CALIFORNIA (Pasadena), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Pasadena is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Pasadena, the City of Burbank (Burbank), the City of Glendale (Glendale), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which

provides, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Pasadena, Burbank, and Glendale; and

WHEREAS this Agreement and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Pasadena desires to purchase and Bonneville desires to sell surplus firm capacity with energy under the terms specified herein; and

WHEREAS Bonneville and Pasadena also desire to enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Term.

This Agreement, when executed, shall become effective at 2400 hours January 31, 1988, and shall terminate at 2400 hours on April 15, 2008;

provided, however, that no power sales may occur subsequent to January 31, 2008. All obligations incurred hereunder shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

2(a) "Agreement" means this sale and exchange agreement between Bonneville and Pasadena.

2(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

2(c) "Contract Demand" means the maximum hourly rate of delivery for surplus firm power when this Agreement operates as a sale, or for capacity when this Agreement operates as an Exchange. This amount is 6 MW for Block 1 and 6 MW for Block 2, and may be modified by Pasadena pursuant to section 4. However, Contract Demand, when used in subsection 7(d), shall mean 12 MW, as may be modified by Pasadena pursuant to section 4.

2(d) "Contract Year" means the year beginning at 2400 hours on June 30 and ending at 2400 hours the following June 30.

2(e) "Embedded Transmission Costs" means a charge equal to the Nonfirm Rate portion of Bonneville's IS-87 Southern Intertie Transmission Rate Schedule or successor rate to the extent Pasadena uses the Pacific Northwest-Pacific Southwest DC Intertie to provide Supplemental Energy to Bonneville; provided, however, that if the Nonfirm Rate portion of IS-87 or successor rate is terminated prior to the expiration of this Agreement, the Parties agree to use an equivalent substitute value calculated using the same methodology Bonneville used to derive the Nonfirm Rate portion of IS-87. Embedded Transmission Costs also shall include a charge equal to Bonneville's ET-87 Energy Transmission Rate Schedule or successor rate to the extent Pasadena provides Supplemental Energy either generated from its resources located outside of Los Angeles County or delivered to Pasadena's points of delivery located outside of Los Angeles County.

2(f) "Energy Account" means an account consisting of (i) monthly totals of the amount of Peaking Replacement Energy and Exchange Energy obligated to be delivered to Bonneville during each month, the delivery of which energy Bonneville has declined pursuant to the provisions of paragraph 7(e)(1), and (ii) the value of such declined energy for each month converted to mills/kWh pursuant to paragraph 7(e)(4). For each month there will be two values in the Energy Account: a total amount of energy declined and the value of such energy in mills/kWh.

2(g) "Exchange" means the capacity for energy exchange terms and conditions as described in this Agreement.

2(h) "Exchange Energy" for Block 1 as defined in subsection 5(a) means the energy Pasadena is obligated to deliver to Bonneville in equal weekly increments throughout the year in Exchange for Bonneville deliveries of capacity on an annual basis. Exchange Energy for Block 2 as defined in subsection 5(b) means the energy Pasadena is obligated to deliver to Bonneville during the period November 16 through April 15 in exchange for Bonneville making available capacity during the preceding May 15 through October 14 period.

2(i) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie transmission lines cross the Nevada-Oregon border.

2(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission capacity due to physical limitations, or (ii) the physical transmission capacity of the DC Intertie is reduced to zero for a period of time which is less than 24-consecutive hours.

2(k) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Pasadena during periods when this Agreement operates as an Exchange or capacity sale pursuant to Section 12.

2(l) "Peaking Replacement Energy" means an amount of energy which Pasadena is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

2(m) "PNW Coordination Agreement" means the contract among Bonneville and Pacific Northwest (PNW) generating entities, providing for coordinated operation of resources, designated as Contract No. 14-03-48221, as amended or replaced.

2(n) "Supplemental Energy" means the energy Pasadena is obligated to make available as a purchase option for Bonneville, pursuant to section 7.

2(o) "Total Incremental Cost" means incremental fuel cost, incremental operation and maintenance, generating unit start-up cost, transmission losses incurred by Pasadena in delivering Supplemental Energy to the Point of Delivery, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Pasadena in supplying Supplemental Energy to Bonneville that would not otherwise have been incurred.

2(p) "Total Outage" means the physical transmission capacity of the DC Intertie is reduced to zero, whether planned or unplanned, for a period of time which equals or exceeds 24-consecutive hours.

2(q)

"UIC" means any unrecoverable incremental costs beyond normal operations incurred by Pasadena in generating or acquiring

Supplemental Energy for which Bonneville rescinds its request pursuant to paragraph 7(c)(3). UIC includes, but is not limited to, direct costs, penalties, cancellation fees for fuel commitments, transmission services, or unrecoverable energy purchases, but excludes general engineering, scheduling, and administrative charges. UIC shall not include costs incurred by Pasadena to the extent that Pasadena is able to make use of such Supplemental Energy and in doing so mitigates costs it has incurred or avoids costs it would otherwise have incurred.

2(r) "Workday" means each day which both Bonneville and Pasadena observe as a regular workday.

3. Exhibits.

Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), General Contract Provisions (Form PSC (SW-1)) (Exhibit B), Plan of Delivery (Exhibit C), Minimum Monthly Energy Distribution Tables for Pasadena (Exhibit D), and Operating Procedures (Exhibit E) are attached hereto and hereby made a part of this Agreement.

4. Option for Pasadena to Increase Purchase.

Not later than June 1, 1988, Pasadena, Burbank, and Glendale may, upon written notice, increase their power purchase by a total of 60 MW, or more, if Bonneville determines power is available for this purpose.

To the extent that any such increase results in an increase for Pasadena pursuant to this Agreement, then that increase shall become effective for the Contract Year beginning at 2400 hours on June 30, 1988, and shall be distributed equally to Blocks 1 and 2 for both the surplus firm power sale and Exchange under this Agreement. This Agreement shall be amended as necessary to reflect such increase.

5. Surplus Firm Power Sale.

5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Pasadena shall purchase 7,610 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Pasadena shall purchase during each Contract Year 18,396 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Pasadena shall purchase during each Contract Year while this Agreement remains a power sale, 21,024 MWh of surplus firm energy.

5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Pasadena shall purchase 6,610 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing until 2400 hours on June 30, 1992, Pasadena shall purchase 2,030 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, and continuing until 2400 hours on October 14, 1992, Pasadena shall purchase 5,342 MWh of surplus firm energy. Beginning at 2400 hours on May 14, 1993, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Pasadena shall purchase 7,711 MWh of surplus firm energy.

5(c) Adjustments to Amount of Power.

The above MWh quantities for Pasadena shall be adjusted as necessary to account for any increase pursuant to section 4. However, in the event of a partial Contract Year power sale for Block 1, or in the

event of a partial May 15 through October 14 power sale for Block 2, Pasadena shall purchase the appropriate monthly amounts of surplus firm energy under Block 1 and under Block 2 as shown in the applicable plan of delivery for such Contract Year pursuant to subsection 5(e). Pasadena may increase the energy scheduled for purchase from Bonneville for any month under the then-current plan of delivery, if such energy is available as determined by Bonneville for such purpose. Such increases shall not affect the plan of delivery, the minimum monthly energy delivery in any future months during such Contract

Year, nor shall any such increase affect the take-or-pay energy amount in any future Contract Year.

5(d) Rates of Delivery.

The maximum hourly rates of delivery for surplus firm power shall be 6 MW from October 15 through May 14 and 12 MW from May 15 through October 14, as may be modified by Pasadena's option to increase pursuant to section 4.

5(e) Distribution of Monthly Amounts.

Prior to January 1 of each year, Pasadena shall submit a plan of delivery to Bonneville showing the distribution of the monthly amounts of energy for the following 4 Contract Years in the form represented by Exhibit C. Pasadena shall distribute the monthly amounts of energy within the limits indicated in Exhibit D.

5(e)(1) If requested by Pasadena, Bonneville shall consult with Pasadena at the time such plans of delivery are being prepared. Bonneville will share its most recent information on its ability to serve Pasadena with a power sale for the following 4 Contract Years and any other considerations that may relate to the plans of delivery. Bonneville shall include such plans of delivery in its PNW Coordination Agreement planning.

5(e)(2) The Parties shall rely upon the most recent plan of delivery submitted to Bonneville for the amount of energy to be delivered in the upcoming July. Bonneville shall notify Pasadena at the earliest opportunity, but not later than August 15, if other than that most recent proposed plan of delivery shall become effective for the balance of the Contract Year. Unless otherwise agreed by the Parties, notwithstanding the limits indicated in Exhibit D, the total of the monthly amounts Bonneville shall deliver during July and August shall equal the 2-month July and August total energy amount specified in the plan of delivery ultimately adopted for use during that Contract Year; provided, however, that in the event that Pasadena is unable to receive the minimum amount of energy during August due to the timing of such notice, then the Parties shall adjust deliveries as necessary prior to November 16 to provide for any energy not received during August.

5(e)(3) If Bonneville adopts a plan of delivery other than the most recent plan of delivery submitted, Bonneville shall adjust the adopted plan of delivery to reflect the most recent Intermountain Power Project scheduled maintenance outages.

5(f) Distribution of Weekly Amounts.

Within any month, Pasadena shall not take more than 135 percent of that month's average weekly amount in any Calendar Week. Such average weekly amount shall be equal to the total MWh for that month as specified in the applicable plan of delivery, divided by the number of days in that month, and multiplied by 7.

5(g) Operational Flexibility.

Pasadena may request changes of up to 5 percent of any monthly amount of energy to be made available under the Agreement, with no less than 2 months' advance written notice. Such changes shall not be unreasonably denied by Bonneville, and the ability to make such changes shall be at no additional cost to Pasadena. The effect of such changed monthly amount on subsequent monthly amounts of energy shall be included in this notice; provided, however, that changes in monthly amounts purchased hereunder shall not be reduced below the minimum monthly amounts of energy specified in Exhibit D, unless mutually agreed to by the Parties.

6. Conversion to the Exchange.

The sale of surplus firm power shall convert to the Exchange if Bonneville has a surplus firm energy insufficiency under the conditions described in this section; provided, however, that Pasadena shall have the option to either: (i) remain in the power sale mode

until after other similar long term sale and exchange agreements executed with parties outside of the Pacific Northwest region for which initial deliveries shall commence after January 1, 1988, have been converted to an exchange; or (ii) convert to the Exchange prior to the conversion of such other similar long term sale and exchange agreements. Pasadena shall exercise its option within 14 days after Pasadena receives Bonneville's written notice that it will be converting this Agreement or such other similar agreements to an exchange.

6(a) Preliminary Notice.

6(a)(1) If Bonneville determines in the PNW Coordination Agreement planning process that there is a possibility of insufficient surplus firm energy to satisfy the surplus firm energy obligation to Pasadena in the next Contract Year, Bonneville shall provide written notice to Pasadena as soon as possible. Following this notice, the Parties may, upon mutual agreement, begin the Exchange at 2400 hours on May 14 or on a subsequent date prior to 2400 hours on June 30 of the then-current Contract Year.

6(a)(2) If Bonneville determines in the planning process that there is a certainty of insufficient surplus firm energy for the next Contract Year, Bonneville shall provide written notice to Pasadena as soon as possible, but not later than June 15. In this event, regardless of the

ext

ent to which PNW system refill occurs, the Exchange shall begin at 2400 hours on June 30. Pasadena's Exchange Energy obligation for Block 2 shall be adjusted to account for a start date of July 1 rather than May 15.

6(b) Final Notice.

If the Exchange does not begin pursuant to subsection 6(a), then the provisions of this subsection apply. The completion of PNW Coordination Agreement planning and the adoption by Bonneville of a particular plan of delivery for Pasadena shall occur after July 31. Bonneville shall provide written notice to Pasadena as soon as possible after July 31, but not later than August 15, whether service at the Contract Demand shall continue as a power sale or convert to the Exchange. If such notice specifies a conversion to the Exchange, then the Exchange shall begin no sooner than 14 days after the date of receipt of such notice by Pasadena. Conversion to the Exchange shall be effective for the remainder of the Contract Year from the time specified in Bonneville's notice to Pasadena, or as provided for in subsection 6(c). Pasadena's Exchange Energy obligation shall be adjusted to account for the start date specified in the notice rather than May 15.

6(c) Reversion to Power Sale.

After conversion to the Exchange, whenever Bonneville determines that it has sufficient surplus firm energy to deliver the amounts

of surplus firm power specified in subsections 5(a) and 5(b) for the ensuing Contract Year, deliveries under this Agreement shall revert to the surplus firm power sale pursuant to section 5, unless Pasadena has provided written notice to Bonneville which describes a contract offer to acquire a resource to replace the energy no longer available from Bonneville due to the conversion to the Exchange. Such notice shall include the amount of energy to be acquired and the term of the proposed acquisition. Bonneville shall respond as follows:

Bonneville shall, within 21 days of receipt of such notice, notify Pasadena as to whether this transaction shall revert to the power sale for the duration of Pasadena's proposed energy acquisition. If this transaction is to revert to the power sale, Bonneville shall notify Pasadena of the basis for the reversion, and such power sale shall begin by the later of (1) 31 days from receipt by Bonneville of Pasadena's notice, or (2) the effective date of energy deliveries pursuant to Pasadena's proposed acquisition, and shall continue for the duration of Pasadena's acquisition, subject to the provisions of section 12. If Bonneville elects not to have the transaction revert to the power sale, then Bonneville shall waive its right to revert to the power sale for the duration of Pasadena's contractual commitment for the proposed energy acquisition. Prior to the termination of Pasadena's acquisition contract, Bonneville shall, upon written notice of at least 30 days, have the right to revert to the power sale as described in section 5 at the termination of Pasadena's acquisition.

6(d) The notice provisions of subsections 6(a) and 6(b) shall apply to reversion from Exchange to power sale, as well as the conversion from power sale to Exchange, except as may be modified by the provisions of subsection 6(c).

7. Capacity For Energy Exchange.

Upon conversion to the Exchange, Bonneville shall make 6 MW of capacity available to Pasadena for Block 1 on an annual basis and 6 MW of capacity for Block 2 from May 15 through October 14 each year, as may be modified by Pasadena's option to increase pursuant to section 4. Pasadena shall be obligated to deliver Peaking Replacement Energy to Bonneville during these periods of capacity deliveries as specified in subsection 7(a). In Exchange for Bonneville deliveries of capacity, Pasadena shall deliver Exchange Energy and make available Supplemental Energy to Bonneville, as specified in subsections 7(b) and 7(c).

7(a) Deliveries of Capacity and Peaking Replacement Energy.

At times when the Exchange is in effect, Bonneville shall make available to Pasadena capacity in an amount up to the Contract Demand each hour, up to 10 hours times the Contract Demand each day Monday through Saturday, including holidays, not to exceed 50 hours times the Contract Demand each week. Pasadena shall be obligated to deliver to Bonneville Peaking Replacement Energy for the amounts of Peaking Energy delivered to Pasadena by 2400 hours

on the day following the Peaking Energy delivery, except as provided in subsection 7(e). Return of Peaking Replacement Energy during any hour shall not exceed 100 percent of the Contract Demand in any hour, unless otherwise mutually agreed by the parties.

7(b) Exchange Energy.

Pasadena shall be obligated to deliver Exchange Energy to Bonneville as provided herein. The amount of such energy provided each Contract Year shall equal the exchange ratio in kWh/kW for each block of capacity, multiplied by the Contract Demand in kilowatts for each block of capacity. For Block 1, the exchange ratio is 2,536 kWh/kW; for Block 2, the exchange ratio is 975 kWh/kW. Exchange Energy for Block 1 shall be delivered in equal weekly increments throughout the year and Exchange Energy for Block 2 shall be delivered in equal weekly increments from November 16 through April 15, except as provided in subsection 7(e). Such equal weekly increments shall be adjusted as necessary to account for an uneven number of weeks during any Exchange Energy delivery period. In the event of a partial Contract Year of capacity deliveries, the amount of Exchange Energy which Pasadena is obligated to deliver to Bonneville shall be reduced on a pro rata basis to account for such partial Contract Year.

7(c) Supplemental Energy.

7(c)(1) Pasadena shall be obligated to make Supplemental Energy available to Bonneville during each November 16 through April 15 while this Agreement operates as an Exchange. The total amount of such energy provided each Contract Year shall equal the supplemental ratio in kWh/kW multiplied by the Block 2 Contract Demand in kilowatts of capacity. The supplemental ratio is 1,200 kWh/kW. Bonneville may elect to purchase up to the maximum amount of Supplemental Energy available to Bonneville in any Contract Year by serving a notice to Pasadena not less than 2 months prior to the desired delivery date, or on shorter notice if agreed to by Pasadena. Bonneville may issue additional notices during any Contract Year for amounts of Supplemental Energy not previously requested in a notice. Any such notice shall specify the amount of Supplemental Energy desired by Bonneville and provide a nonbinding proposed schedule for deliveries of Supplemental Energy. Pasadena shall promptly notify Bonneville if such proposed schedule is unacceptable to Pasadena and the reasons therefor. Pasadena shall not unreasonably deny Bonneville's proposed schedule. In the event that the Parties are unable to agree on a proposed schedule, then the requested Supplemental Energy shall be delivered in equal hourly increments during the delivery period specified in Bonneville's notice and during the

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rs specified in paragraph 7(d)(3). Bonneville and Pasadena shall finalize the schedule for deliveries of weekly blocks of Supplemental Energy within 15 Workdays of receipt by Pasadena of Bonneville's notice. Deliveries of Supplemental Energy are subject to Pasadena's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Pasadena's generation or transmission capability. In the event of any such constraints, Pasadena shall reschedule such deliveries in a timely manner. In the event of an extended generation constraint, Bonneville may request an alternate available source for Supplemental Energy at another agreed upon price, until such time as the generation constraint is removed.

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hin 15 Workdays of receipt of Bonneville's notice requesting to make available Supplemental Energy, and prior to committing to obtain Supplemental Energy, Pasadena shall inform Bonneville of probable resources available, including the estimated price of the lowest cost sources of Supplemental Energy available for purchase, the estimated Total Incremental Cost from such sources, and the UIC for such resources. Pasadena shall revise such estimated price, Total Incremental Cost, and UIC if conditions change substantially during the remaining days of the notice period described in

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agraph 7(c)(1). If Pasadena determines that the UIC from such sources will exceed 4.5 mills, as escalated pursuant to subsection 9(c), it shall notify Bonneville, and Bonneville shall have the option of either: (1) raising such maximum rate for UIC; (2) relieving Pasadena of its obligation to provide Supplemental Energy; or (3) obligating itself to purchase Supplemental Energy. Bonneville shall make this choice in a timely manner. Pasadena shall use best efforts to mitigate UIC, but unless earlier notification by Pasadena and Bonneville's selection of its option to raise the maximum rate for UIC has occurred, Bonneville's obligation for the amount of energy specified in its notice of rescission shall not exceed 4.5 mills/kWh as escalated pursuant to subsection 9(c).

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neville shall pay Pasadena any applicable Embedded Transmission Costs plus 115 percent of Pasadena's Total Incremental Cost for providing Supplemental Energy. Bonneville may rescind a notice requesting Supplemental Energy not later than 0930 hours of the Workday immediately preceding the day when such Supplemental Energy was to begin to be provided to Bonneville, and pay Pasadena any UIC incurred by Pasadena in response to Bonneville's previous request for such energy. Any decision to rescind a notice requesting Supplemental Energy shall apply to the total amount of MWh of

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plemental Energy requested by Bonneville pursuant to paragraph 7(c)(1); provided, however, that Bonneville can rescind a portion of the Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1) if Bonneville agrees to pay any new UIC resulting therefrom.

7(c)(4) Bonneville shall submit schedules for the delivery of Supplemental Energy pursuant to the provisions of paragraph 7(c)(1) and section 10. Pasadena shall not unreasonably withhold its agreement with such schedules, and Pasadena shall deliver weekly amounts of Supplemental Energy by the end of each Calendar Week during the period of deliveries pursuant to the mutually agreed upon schedules for the delivery of Supplemental Energy.

7(d) Delivery Limitations.

7(d)(1) May 15 through October 14.

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ess limited by Bonneville, Pasadena shall complete each Calendar Week's deliveries of Exchange Energy by the end of such Calendar Week. The maximum rate of delivery for Peaking Replacement Energy plus Exchange Energy shall be 100 percent of the Contract Demand. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account. Bonneville may limit the delivery rate for

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king Replacement Energy plus Exchange Energy to not less than 60 percent of Contract Demand for the Exchange during the period May 15 through October 14. To the extent that Bonneville restricts the delivery on any hour, the restricted quantity of Peaking Replacement Energy and Exchange Energy may either be delivered by Pasadena on hours other than the hours specified in paragraph 7(d)(3), or be delivered on the next available normal delivery hour when Bonneville can accept such energy. The Parties may agree to delay the delivery beyond the Calendar Week of delivery, or the Parties may agree to place such energy into the Energy Account, as described in paragraph 7(e)(1).

7(d)(2) November 16 through April 15.

Hourly rates of delivery shall be as mutually agreed upon by Bonneville and Pasadena. However, during the period November 16 through April 15, during any hour the total rate of delivery for Exchange Energy plus Supplemental Energy plus Peaking Replacement Energy shall not exceed 250 percent of the Contract Demand, unless mutually agreed to by Bonneville and Pasadena. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account.

7(d)(3) Normal Delivery Hours for Peaking Replacement and Exchange Energy.

Although deliveries of Peaking Replacement Energy and Exchange Energy may occur during other hours, the normal delivery hours are as follows:

2200 hours on Monday to 0800 hours on Tuesday
2200 hours on Tuesday to 0800 hours on Wednesday
2200 hours on Wednesday to 0800 hours on Thursday
2200 hours on Thursday to 0800 hours on Friday
2200 hours on Friday to 0800 hours on Saturday
2200 hours on Saturday to 0800 hours on Monday.

7(e) Conditions for Energy Account and Cash-Out of Peaking Replacement and Exchange Energy.

7(e)(1) Declinations of Peaking Replacement Energy and Exchange Energy.

Bonneville may decline deliveries of either Peaking Replacement Energy or Exchange Energy in whole or in part. Bonneville shall provide Pasadena with notice by 1400 hours on the Thursday prior to each Calendar Week. Such notice shall specify whether Bonneville will require the delivery of such energy in whole or in part for the next Calendar Week and shall specify the amount of energy which Bonneville declines. To the extent that Bonneville declines the deliveries, the monthly total of such declined energy and its value converted to mills/kWh

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suant to paragraph 7(e)(4) shall be entered into the Energy Account.

7(e)(2) Withdrawals from the Energy Account.

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neville may request to withdraw energy from the Energy Account during a Calendar Week and shall provide Pasadena with notice by 1400 hours on the Thursday prior to such Calendar Week. Such notice shall specify the quantity of energy to be withdrawn and the rate of delivery for such energy. However, in addition to other deliveries by Pasadena pursuant to this Agreement, the maximum rate of withdrawal from the Energy Account shall not exceed the Contract Demand on any hour, unless mutually agreed. Pasadena shall provide such requested energy to Bonneville during the next Calendar Week, subject to Pasadena's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Pasadena's generation or transmission capability. The value for energy withdrawn from the Energy Account shall be converted to kWh as determined pursuant to paragraph 7(e)(4) and shall be withdrawn on a first-in-first-out basis. To the extent that the value for withdrawn energy is greater than the value for declined energy determined pursuant to paragraph 7(e)(1), Bonneville shall pay Pasadena an amount equal to the

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ference between the values for withdrawn and declined energy multiplied by the kWh withdrawn. To the extent that the value for withdrawn energy is less than the value for declined energy determined pursuant to paragraph 7(e)(1), Pasadena shall pay Bonneville an amount equal to the difference between the values for declined and withdrawn energy multiplied by the kWh withdrawn. Each party shall pay the other pursuant to the provisions of section 8. If mutually agreed, withdrawn energy may be provided on hours other than those specified in paragraph 7(d)(3).

7(e)(3) Cash-Out of Energy in the Energy Account.

Bon

neville shall maintain the Energy Account. The Energy Account shall contain monthly totals of (i) the declined energy remaining at the end of each calendar month, and (ii) the value of such energy converted to mills/kWh pursuant to paragraph 7(e)(4). Any monthly total of energy which remains in the Energy Account longer than 11 months shall be cashed out pursuant to subsection 9(b) at the cash-out price at the time the energy was entered into the Energy Account. No more than one monthly total of energy shall be cashed out on any monthly bill rendered to Pasadena. Pasadena shall pay Bonneville pursuant to the cash-out terms specified in subsection 9(b), and shall be relieved of any obligation

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reafter to provide such monthly total of energy to Bonneville.

7(e)(4) Determination of Value for Energy Entered into Energy Account and Withdrawn from Energy Account.

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lowing receipt of its gas bill each month, Pasadena shall provide Bonneville with a copy of a portion of such bill which shows the dollars per dekatherm paid by Pasadena for the total of all gas purchases for that month. Bonneville shall convert this amount to dollars per Btu and apply this ratio to an agreed-upon heat rate of 10,000 Btu per kWh to determine the value in mills per kWh for entries into and withdrawals from the Energy Account during the following month. To the extent that gas is not available or is no longer a significant fuel source for generation by Pasadena, the Parties shall negotiate: (i) an alternate significant fuel source which is used by Pasadena for generation; and (ii) a methodology to derive a value in mills/kWh for entries into and withdrawals from the Energy Account. This Agreement shall be amended to implement the results of such negotiation.

7(f) At Pasadena's request, the Parties agree to negotiate in good faith mutually agreeable terms and conditions which would allow Pasadena to deliver energy to Bonneville's system for later use by Pasadena.

8. Payment.

8(a) Payment by Pasadena.

Bonneville shall render preliminary and final adjusted monthly bills to Pasadena. Pasadena shall pay Bonneville by the close of business on the twentieth (20th) day after the date of each such preliminary bill and any adjustments that may occur on the final monthly bill. The date of such bills shall be no earlier than the mailing date of such bills. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Pasadena, then the due date shall be the next following business day. Other provisions related to payment of bills shall be in accordance with the General Rate Schedule Provisions attached to this Agreement.

8(b) Payment by Bonneville.

Pasadena shall render monthly bills to Bonneville. Bonneville shall pay Pasadena by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to payment of bills shall be in accordance with the General Rate Schedule provisions attached to this Agreement.

9. Rates and Cash-Out.

9(a) Surplus Firm Power.

9(a)(1) Initial Demand and Energy Rates.

The initial demand and energy rates for deliveries of power under Block 1 and Block 2 are as follows: $4.60/kilowatt-month (kW-mo.) and 20.5 mills/kWh (includes Intertie adder). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery.

9(a)(2) Rate Adjustment During First 5 Years.

The initial demand and energy rates for the period January 1, 1988, through December 31, 1988, are described in paragraph 9(a)(1). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. The energy rates specified in this paragraph 9(a)(2) include the Intertie adder. The rates for calendar years 1989 through 1992 are as follows:

Calendar Year	Capacity ($/kW-mo.)	Energy (mills/kWh)
1989	4.88	21.73
1990	5.17	23.03
1991	5.48	24.42
1992	5.81	25.88

Subsequent to December 31, 1992, the demand and energy rates shall be adjusted pursuant to paragraph 9(a)(3).

9(a)(3) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

Adjustments under this paragraph begin January 1, 1993. For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. On the effective date of any Bonneville Priority Firm Power (PF) rate adjustment thereafter, the rate for surplus firm power (SL_{new}) shall be adjusted as follows:

$$SL_{new} = SL_n * \frac{PF_{new}}{PF_{prev}}$$

where

SL_{new} = The effective surplus firm power demand and energy charges hereunder as adjusted to reflect the change between PF_{new} and PF_{prev}.

SL_n = For the initial adjustment under this paragraph 9(a)(3) the SL_n demand charge shall be $5.81/kW-mo. and the energy charge shall be 25.88 mills/kWh. For all subsequent adjustments under this paragraph, the values for SL_n shall be the then-current values for the previous SL_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be

determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh, in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(b) Cash-out.

Bonneville shall cash out energy pursuant to paragraph 7(e)(3). Pasadena shall pay Bonneville for such energy as provided below.

9(b)(1) Initial Cash-out.

The initial level for cash-out shall be 14.9 mills/kWh.

9(b)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any PF rate adjustment after the effective date of this Agreement, the level of the cash-out rate (CO_{new}) shall be adjusted as follows:

$$CO_{new} = CO_{n} * \frac{PF_{new}}{PF_{prev}}$$

where CO_{new} = The effective level for cash-out as adjusted to reflect a new PF rate.

CO_n = For the initial adjustment under this paragraph 9(b)(2), CO_n shall be 14.9 mills/kWh. For all subsequent adjustments under this paragraph, the values for CO_n shall be the then-current values for the previous CO_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(c) Maximum Rate for UIC Incurred by Pasadena if Bonneville Rescinds a Notice for Supplemental Energy.

9(c)(1) Initial Maximum Rate for UIC.

In accordance with subsection 7(c), the initial rate for UIC is 4.5 mills/kWh for the amount of energy specified in Bonneville's notice of rescission.

9(c)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any Priority Firm Power (PF) rate adjustment after the effective date of this

Agreement, the maximum rate for UIC (UIC_{new}) shall be adjusted as follows:

$$UIC_{new} = UIC_{n} * \frac{PF_{new}}{PF_{prev}}$$

where

UIC_{new} = The effective rate for UIC as adjusted to reflect a new PF rate.

UIC_{n} = For the initial adjustment under this paragraph 9(c)(2), UIC_{n} shall be equal to 4.5 mills/kWh. For all subsequent adjustments under this paragraph, the values for UIC_{n} shall be the then-current values for the previous UIC_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

10. Scheduling Provisions for Power Sale and Exchange.

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

10(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

10(b) Prescheduled amounts shall be submitted by 0930 hours.

10(c) This subsection 10(c) shall apply only to the power sale portion of this transaction. If Pasadena desires to schedule other than that month's average weekly amount of energy for such month in any Calendar Week, Pasadena shall notify Bonneville by 1400 hours on the Monday preceding such Calendar Week. Pasadena may revise such new weekly amount if Pasadena notifies Bonneville by 1400 hours on the Thursday preceding such Calendar Week.

10(d) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts that Pasadena anticipates it will schedule from Bonneville each day for the following 10 days. Pasadena shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Pasadena or Bonneville to schedule such amounts.

10(e) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such changes

shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

11. Transmission Limitation.

In the event of an interruption of deliveries by either Party due to a DC Intertie outage, the following provisions shall apply.

11(a) Relief Remedies During Periods of Total Outage.

The Parties shall be relieved of obligations as follows.

11(a)(1) Conditions for Capacity Payment Relief.

The following conditions must be met each Contract Year for relief to be given as described in paragraph 11(a)(2): (i) the duration of a single Total Outage exceeds 360-consecutive hours, in which case relief is provided for the remainder of such Total Outage only; or (ii) the sum of all Total Outages for the Contract Year exceeds 720 hours, excluding Total Outages, if any, for which relief was given pursuant to item (i) above.

11(a)(2) Determination of Capacity Payment Relief.

For the duration of the Total Outages which occur subsequent to the occurrence of relief as described in

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agraph 11(a)(1), Pasadena shall receive a capacity credit in the form of a reduction in the demand rate per kW-mo. calculated by determining such duration of the Total Outage during the billing month, divided by the total number of hours in that month.

11(a)(3) Energy Payment Relief During Power Sale.

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hout regard to the duration of a Total Outage, if Pasadena is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Pasadena shall be relieved of its obligation to pay for such amounts of energy. To the extent that Pasadena is unable to receive energy during any month, the monthly minimum take-or-pay energy specified in the applicable plan of delivery shall be reduced by an amount of energy determined as follows: a ratio shall be calculated, the numerator being the number of hours of Total Outage during the month that Pasadena is unable to receive energy, and the denominator being the total number of hours in that month. This ratio is then multiplied by the monthly energy specified in the applicable plan of delivery to determine such amount of energy. This amount of energy shall be subtracted from such monthly energy to determine the revised monthly amount for that month. The total take-or-pay energy for Block 1, or Block 2 if

app

licable, as specified in Exhibit D, shall be reduced by the amount of energy as calculated above.

11(a)(4) Energy Payment Relief During Exchange.

11(a)(4)(A) For Total Outages which occur subsequent to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Pasadena's obligation to deliver Peaking Replacement Energy owed to Bonneville for previous capacity delivered by Bonneville, and Supplemental Energy requested by Bonneville pursuant to subsection 7(c) remain. Pasadena's obligation to deliver Exchange Energy associated with a Total Outage up to one year remains, but, at Bonneville's option, either: (i) Pasadena shall deliver such energy to Bonneville subject to mutually agreed upon schedules following the end of the Total Outage and Bonneville shall pay Pasadena's Total Incremental Cost for the first 3 months of such obligation and 115 percent of Pasadena's Total Incremental Cost for the following 9 months; or (ii) Pasadena shall be relieved of its obligation to deliver such energy.

11(a)(4)(B) For Total Outages which occur prior to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Pasadena shall reschedule deliveries of Peaking Replacement Energy, Exchange Energy, and Supplemental Energy which Pasadena is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the Total Outage, or at other times as mutually agreed by the Parties.

11(b) Relief Remedies During Periods of Partial Outage.

11(b)(1) Relief Remedies During the Power Sale.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue deliveries under this Agreement. The Parties also shall curtail pro rata on an hourly basis all agreements executed on or before January 1, 1988, for firm energy or capacity based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over agreements executed after January 1, 1988 for firm energy or capacity. If Pasadena is unable to receive any amounts of energy, Bonneville shall be relieved of

its obligation to deliver and Pasadena shall be relieved of its obligation to pay for such amounts of energy.

11(b)(2) Relief Remedies During the Exchange.

During the Exchange, or during any period of the power sale when Bonneville has restricted surplus firm energy deliveries pursuant to section 12 and is delivering capacity only, the following provisions shall apply.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue or reschedule deliveries under this Agreement. The Parties shall curtail all agreements for firm capacity without energy or deliveries of exchange energy executed prior to January 1, 1988, pro rata on an hourly basis, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over deliveries of capacity or exchange energy pursuant to agreements executed after January 1, 1988. Pasadena shall reschedule interrupted or curtailed deliveries of Peaking Replacement Energy, Exchange Energy and Supplemental Energy which Pasadena is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the

interruption or curtailment, or at other times and under conditions as mutually agreed by the Parties.

12. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of 16 U.S.C. § 837 (1984) (P.L. 88-552), and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to those provisions, Bonneville shall have the right to restrict all or a portion of the capacity or energy if such capacity or energy is needed to meet the capacity or energy requirements, as the case may be, in the PNW. Such restrictions shall be limited in amounts and duration to cover the projected need specified in the written notice which Bonneville shall provide to Pasadena. Such written notice shall specify the date on which a period of restriction begins and the date on which such period of restriction is projected to end. The sale of surplus firm power shall resume pursuant to the applicable plan of delivery for the remainder of the then-current Contract Year after expiration of the period of restriction except as described in the immediately following sentence. If a projected period of restriction exceeds 2 months' duration, Pasadena may make other arrangements for energy for the remainder of such Contract Year if Pasadena has entered into a contractual commitment with a third party as a direct result of Bonneville's prior notice of restriction, and Bonneville has received Pasadena's written notice of such arrangements not later than 10 days prior to the projected end of such period of restriction.

During any period that Bonneville continues to have surplus firm energy on a planning basis, but Bonneville restricts the delivery of

energy as provided above, Bonneville shall make available capacity at the Contract Demand and, in the event of a partial energy restriction, a pro rata amount of energy. Prior to the effective date of the restriction, Pasadena shall give notice to Bonneville of the amount of capacity made available by Bonneville that Pasadena desires for the anticipated duration of the restriction. In such notice, Pasadena may reduce the amount of capacity it desires for the anticipated period of restriction below the Contract Demand, with no change in the rate per kW-mo. of capacity specified in section 9; provided, however, that if Pasadena reduces the amount of capacity it desires during a period of restriction to zero, and the reduction to zero capacity occurs on any day other than the last day of a month, then Bonneville shall make a pro rata reduction in the rate per kW-mo. of capacity. Terms for the delivery of such capacity and for the cash-out or delivery of Peaking Replacement Energy shall be as provided in this Agreement.

13. Points of Delivery.

13(a) Points of Delivery.

The point of delivery for all deliveries pursuant to this Agreement is NOB.

13(b) Other Pacific Southwest Points of Delivery.

Notwithstanding the point of delivery specified in subsection 13(a), at Bonneville's request, Pasadena shall

deliver energy owed Bonneville to Pacific Southwest points of delivery where Pasadena has interconnections and available transmission capacity with Pacific Southwest utilities.

13(c) Costs Incurred to Point of Delivery.

Each Party shall bear its own costs for deliveries to the point of delivery under subsections 13(a) and 13(b); provided, however, that all deliveries of Supplemental Energy by Pasadena to Bonneville pursuant to subsection 7(c) shall be excluded from the provisions of this subsection.

14. Limit of Liability.

It is mutually understood and agreed that Pasadena's obligations for the payment of monies pursuant to this Agreement are limited to revenues received by Pasadena from the sale of electric power and/or the disposition of assets of Pasadena's power generation and transmission facilities.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By/S/ JAKMES J. JURA
Administrator

Date January 28, 1988

CITY OF PASADENA, CALIFORNIA

By/S/ EARL K. AHGAJANI

Title Deputy City Manager

Date 1/06/88

PLAN OF DELIVERY

1. Monthly Amounts of Energy Requested by Pasadena Pursuant to Subsection 5(e).

Year / Month	1988	1989	1990	1991
July				
August				
September				
October				
November				
December				
January				
February				
March				
April				
May				
June				

This attachment will be revised each year upon Pasadena's submission of new data.

2. Example, assuming 1992 Power Sale.

Upon Pasadena's submittal of plans of delivery each year in accordance with subsection 5(e), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations. Assuming energy sufficient to serve Pasadena load as a power sale, the plan of delivery to be used is based upon the degree to which the coordinated system refills.

At 2400 hours on July 31, 1992, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will implement the most recent plan of delivery submitted by Pasadena. If the system does not refill, such parties will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier "Critical Periods"). This can be shown as follows:

Critical Period	Pasadena's Plan of Delivery
1992 - 1995 (refill)	year 1992 from 1992 submittal
1991 - 1994	year 1992 from 1991 submittal
1990 - 1993	year 1992 from 1990 submittal
1989 - 1992	year 1992 from 1989 submittal

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

Contract No. DE-MS79-87BP92413
City of Pasadena
Effective at 2400 hours January 31, 1988

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR PASADENA

	BLOCK 1: 6 MW DEMAND			BLOCK 2: 6 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	19%	= 848					848
F	19%	= 766					766
M	25%	= 1,116					1,116
A	32%	= 1,382					1,382
M	35%	= 1,562	May (15-31)	30%	= 734		2,296
J	35%	= 1,512		30%	= 1,296		2,808
J	41%	= 1,830		30%	= 1,339		3,169
A	41%	= 1,830		33%	= 1,473		3,303 1/
S	41%	= 1,771		30%	= 1,296		3,067
O	32%	= 1,328	Oct. (1-14)	9%	= 181		1,609
N	19%	= 821					821
D	19%	= 848					848
TOTAL		15,714			6,319		
TAKE-OR-PAY		18,396 2/			6,610 2/		
BLOCK 1 LF = 35%				BLOCK 2 LF = 30%			

1/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

2/ These figures will be increased on July 1, 1992, pursuant to page 2 of this Exhibit D.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR PASADENA

	BLOCK 1: 6 MW DEMAND			BLOCK 1: 6 MW DEMAND			BLOCK 2: TOTAL MWh
	LF	=	MIN. MWh	LF	=	MIN. MWh	
J	20%	=	893				893
F	20%	=	806				806
M	27%	=	1,205				1,205
A	33%	=	1,426				1,426
M	37%	=	1,652 (May 15-31)	32%	=	783	2,435
J	37%	=	1,598	32%	=	1,382	2,980
J	43%	=	1,920	32%	=	1,428	3,348
A	43%	=	1,920	35%	=	1,562	3,482 1/
S	43%	=	1,858	32%	=	1,382	3,240
O	33%	=	1,473 (Oct. 1-14)	10%	=	202	1,675
N	20%	=	864				864
D	20%	=	893				893
TOTAL			16,508			6,739	
TAKE-OR-PAY			21,024			7,711	

BLOCK 1 LF = 40%

BLOCK 2 LF = 35%

1/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

OPERATING PROCEDURES

No operating procedures have been established as of the date of execution of this Agreement.

Prior to conversion to the Exchange, the Parties agree to develop operating procedures which shall be utilized during the Exchange. Such procedures shall include, but are not limited to, determination and verification of Total Incremental Cost, determination and verification of UIC, operating procedures under the Energy Account, and operating procedures during periods of Total Outage and Partial Outage.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in this Agreement.

(WP-PKLD-3462c)

Contract No. DE-MS79-90BP92858

4/9/90

FIRM PEAKING CAPACITY SALE/EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

RIVERSIDE, CALIFORNIA

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Exhibit A (Wholesale Power Rate Schedules and General
General Rate Schedule Provisions) .....
Exhibit B (Bonneville General Contract Provisions Form PSC (SW-1)) ....
Exhibit C (16 U.S.C. Section 837 (1984) Public Law 88-552) .....

Bonneville-Riverside

Firm Peaking Capacity Sale/Exchange Agreement

This FIRM PEAKING CAPACITY SALE/EXCHANGE AGREEMENT (Agreement) is executed as of June 15, 1990, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville"), and the CITY OF RIVERSIDE, CALIFORNIA ("Riverside"), a municipal corporation of the State of California. Bonneville and Riverside hereinafter sometimes are referred to individually as "Party" and collectively as "Parties".

WITNESSETH

WHEREAS Bonneville sells electric capacity at wholesale, and projects availability of amounts in excess of its existing obligations to deliver such capacity to its Pacific Northwest customers; and

WHEREAS Riverside is the owner of an electric generation, transmission and distribution system which it uses to supply electric energy to its customers and other utilities; and

WHEREAS Riverside has obtained or intends to obtain transmission service between the Nevada-Oregon border and Sylmar Substation on the DC Intertie (DC Intertie Transmission Service Agreement); and

WHEREAS Riverside and the Southern California Edison Company (SCE) have entered or intend to enter into an agreement which provides for SCE to transmit electric power and energy acquired pursuant to this Agreement between the Sylmar Substation and the point where the electrical facilities of Riverside and SCE interconnect (SCE-Riverside Sylmar Firm Transmission Service Agreement); and

WHEREAS Riverside desires to (i) exchange capacity obtained from Bonneville during the Summer Season for energy returned to Bonneville during the Delivery Season and (ii) purchase capacity from Bonneville during the Winter Season, using the transmission capacity obtained under the DC Intertie Transmission Service Agreement and the SCE-Riverside Sylmar Firm Transmission Service Agreement under the terms specified herein; and

WHEREAS Bonneville is authorized pursuant to law to dispose of surplus electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority.

NOW, THEREFORE, the Parties hereto agree as follows:

1. Effective Date and Term.

(a) Effective Date.

Unless otherwise agreed, this Agreement shall become effective at 0001 hours on the first day of the first month after the occurrence of all the following events (Effective Date).

(1) Execution of this Agreement by both Parties; and

(2) Execution and acceptance for filing by the FERC, of the SCE-Riverside Supplemental Integration Agreement between SCE and Riverside; and

(3) Execution and acceptance for filing by the FERC, of the SCE-Riverside Sylmar Firm Transmission Service Agreement; and

(4) Execution of the DC Intertie Transmission Service Agreement(s).

(b) Term.

This Agreement shall remain in full force and effect until the earlier of (i) twenty (20) years from the Effective Date; or (ii) the date the SCE-Riverside Sylmar Firm Transmission Service Agreement terminates; or (iii) the date the DC Intertie Transmission Service Agreement(s) terminate(s), unless replaced by other agreements or other suitable arrangements. All obligations incurred hereunder prior to termination shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified.

(a) "Calendar Week" means the week beginning at 0001 hours on Sunday and ending at 2400 hours on the following Saturday.

(b) "Contract Demand" means the maximum hourly rate of delivery for Firm Peaking Capacity and associated Firm Peaking Energy, determined pursuant to sections 4(a) and 5(a).

(c) "Delivery Season" means the period beginning at 0001 hours on October 1 and ending at 2400 hours on the following April 15, unless extended by Bonneville pursuant to section 7(b)(2).

(d) "DC Intertie" means that portion of the direct-current 1000 kilovolt extra high voltage electric transmission line between California and the Pacific Northwest.

(e) "Energy Account" means an account consisting of monthly totals of Exchange Energy and Peaking Replacement Energy, the delivery of which Bonneville has deferred pursuant to sections 4(c) and 6(b), or energy not rescheduled pursuant to the provisions section 8(c).

(f) "Exchange Energy" means the energy Riverside is obligated to deliver to Bonneville during a Delivery Season in exchange for Bonneville deliveries of Firm Peaking Capacity the preceding June 1 to October 31.

(g) "FERC" means The Federal Energy Regulatory Commission, or its successor.

(h) "Firm Peaking Capacity" means the capacity delivered by Bonneville to Riverside pursuant to this Agreement.

(i) "Firm Peaking Energy" means the energy associated with Bonneville's deliveries of Firm Peaking Capacity.

(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission rights under the DC Intertie Transmission Service Agreement(s) due to physical or operating limitations, or (ii) a complete interruption of deliveries due to a reduction of available DC Intertie transmission rights under the DC Intertie Transmission Service Agreement(s) due to physical or operating limitations, for a period of time which is less than twenty-four (24) consecutive hours.

(k) "Peaking Replacement Energy" means the energy which Riverside is obligated to deliver to Bonneville, pursuant to section 6, to replace Firm Peaking Energy supplied by Bonneville.

(l) "Point of Delivery" means the point(s) where deliveries of electric power and energy between the Parties takes place pursuant to section 9.

(m) "SCE-Riverside Supplemental Integration Agreement" means the agreement executed between SCE and Riverside for the integration of capacity and energy acquired pursuant to this Agreement.

(n) "Summer Season" means the period beginning at 0001 hours on June 1 and ending at 2400 hours on the following October 31.

(o) "Total Incremental Cost" means the sum of the incremental fuel cost, incremental operation and maintenance cost, generating unit start-up cost, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Riverside in supplying Exchange Energy to Bonneville, including transmission losses incurred by Riverside in delivering Exchange Energy to the Point of Delivery, that would not otherwise have been incurred.

(p) "Total Outage" means the complete interruption of deliveries due to a reduction of available DC Intertie transmission rights under the DC Intertie Transmission Service Agreement(s), for a period of time which equals or exceeds twenty-four (24) consecutive hours.

(q) "Uncontrollable Force" means any act or event beyond the control of a Party which adversely affects the ability of the Party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid, including, but not

limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning, and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage, and restraint by court order or by regulatory authorities; and, after a good faith effort by the appropriate Party to so obtain, action or nonaction by or failure to obtain the necessary authorizations or approvals from any governmental agency or regulatory authority.

(r) "Winter Season" means the period beginning at 0001 hours on November 1 and ending at 2400 hours on the following May 31.

(s) "Workday" means each day which both Bonneville and Riverside observe as a regular day of work.

3. Exhibits.

Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), Bonneville's General Contract Provisions (Form PSC (SW-1)) (Exhibit B), and 16 U.S.C. Section 837 (1984) (Public Law 88-552) (Exhibit C), are attached hereto and hereby made a part of this Agreement. In the event a provision of Exhibit A or B conflicts with sections 1 through 20 of this Agreement, then the provisions of sections 1 through 20 of this Agreement shall control. In the event a provision in Exhibit B conflicts with a provision of Exhibit A, then the provision in Exhibit A shall control.

4. Capacity for Energy Exchange.

(a) Firm Peaking Capacity and Energy.

(1) During the Summer Season, the Contract Demand shall be twenty-three (23) megawatts (MW).

(2) Bonneville shall make available to Riverside Firm Peaking Capacity each hour in an amount equal to the Contract Demand. Firm Peaking Energy shall be delivered pursuant to the scheduling provisions of section 11, in daily amounts, including holidays, up to ten (10) megawatthours (MWH) per MW of Contract Demand, and in Calendar Week amounts up to fifty (50) MWH per MW of Contract Demand.

(b) Exchange Energy.

(1) Riverside shall, in return for Firm Peaking Capacity made available by Bonneville the preceding June 1 to October 31, deliver Exchange Energy to Bonneville each Delivery Season as provided herein. The amount of such energy provided each Delivery Season shall equal the exchange ratio in MWH/MW multiplied by the Contract Demand in MW for such capacity. The exchange ratio shall be twelve hundred (1200) MWH/MW.

(2) Unless otherwise agreed, except as provided in section 4(c), Exchange Energy shall be delivered in October during weekend hours to the extent the Parties anticipate such deliveries are required to meet Riverside's Exchange Energy obligation during that Delivery Season. The remaining balance of Exchange Energy shall be delivered in equal weekly increments during the period of November 1 through April 15, unless otherwise agreed by the Parties.

(3) Except as provided in section 8, if Bonneville makes Firm Peaking Capacity available for less than a full Summer Season, the amount of Exchange Energy which Riverside is obligated to deliver to Bonneville shall be reduced proportionately to account for the partial deliveries of Firm Peaking Capacity.

(c) Exchange Energy Delivery Limitations.

(1) Unless otherwise agreed the maximum hourly rate of delivery for Exchange Energy shall be 100 percent of the Contract Demand set forth in section 4(a)(1). Upon agreement of the Parties' schedulers, and subject to Riverside making arrangements for additional intertie capacity or counter-scheduling against a Bonneville delivery to Riverside: (i) during the months of October, November, December, January, and February, the maximum hourly rate of delivery for Exchange Energy shall be 200 percent of the Contract Demand set forth in section 4(a)(1); and (ii) during the months of March and April, the maximum hourly rate of delivery for Exchange Energy shall be 130 percent of the Contract Demand set forth in section 4(a)(1); provided, however that such maximum hourly rates of delivery shall be reduced by an amount equal to the amount of Peaking Replacement Energy concurrently being delivered pursuant to section 6.

(2) Subject to Partial Outages and Total Outages, and unless limited by Bonneville pursuant to sections 4(c)(3) and 4(c)(4), Riverside shall complete each Calendar Week's obligation to deliver Exchange Energy by the end of such Calendar Week.

(3) At the time schedules for the delivery of Exchange Energy are established by Riverside pursuant to section 11, Bonneville may limit the delivery rate for Exchange Energy to not less than sixty (60) percent of the then applicable Contract Demand.

(4) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Exchange Energy, including down to zero (0).

(5) To the extent that Bonneville restricts the delivery of Exchange Energy, Bonneville may (i) place such energy into the Energy Account as described in section 7; or (ii) the Parties may mutually agree to delay the delivery of such energy.

5. Firm Peaking Capacity Sale.

(a) Firm Peaking Capacity and Energy.

(1) During the Winter Season, the Contract Demand shall be sixteen (16) MW for the months of November through April and twenty-three (23) MW for the month of May.

(2) Bonneville shall make available to Riverside and Riverside shall purchase Firm Peaking Capacity each hour in an amount equal to the Contract Demand. Firm Peaking Energy shall be delivered pursuant to the scheduling provisions of section 11, in daily amounts, including holidays, up to ten (10) MWH per MW of Contract Demand, and in Calendar Week amounts up to fifty (50) MWH per MW of Contract Demand.

(3) Except as provided in section 8, if Bonneville makes Firm Peaking Capacity available for less than a full month, the demand charge shall be reduced pro-rata,

(b) Demand Charge.

The demand charge for Firm Peaking Capacity made available by Bonneville each November 1 through May 31 and applied to the Contract Demands specified in section 5(a) shall initially be $4.65 per kilowatt-month.

Each October 1, beginning October 1, 1990, the demand charge shall be recalculated as follows and rounded to the nearest cent:

$$SPnew = SPprev * \frac{PFnew}{PFprev} * 1.01$$

Where:

SPnew = The Firm Peaking Capacity demand charge, as adjusted hereunder to become effective each October 1, in dollars per kilowatt-month.

SPprev = The Firm Peaking Capacity demand charge in effect immediately prior to each October 1, in dollars per kilowatt-month.

PFprev = The average Bonneville Priority Firm (PF) rate, or successor rate(s) thereto, in effect the previous October 1, in mills per kilowatthour (kWh). Such average PF rate, and any successor rate(s), shall be calculated to the nearest hundredth of a mill at a load factor of fifty (50) percent, and assuming a uniform demand in each month. If there is more than one PF rate,

or successor rate(s), the average shall be determined by a weighting based on forecasted sales in the relevant rate case.

PFnew = The average PF rate, or successor rate(s) thereto, in effect on each October 1 contract rate adjustment date, in mills per kWh. Such average PF rate, and any successor rate(s), shall be calculated to the nearest hundredth of a mill at a load factor of fifty (50) percent, and assuming a uniform demand in the each month. If there is more than one PF rate, or successor rate(s), the average shall be determined by a weighting based on forecasted sales in the relevant rate case.

6. Peaking Replacement Energy.

(a) Obligation to Deliver.

Subject to section 8(b), Riverside shall be obligated to return Peaking Replacement Energy to Bonneville equal to the amounts of Firm Peaking Energy previously delivered to Riverside by 2400 hours on the day following Bonneville's prior Firm Peaking Energy delivery.

(b) Peaking Replacement Delivery Limitations.

(1) Unless otherwise agreed, the maximum hourly rate of delivery of Peaking Replacement Energy shall be one hundred (100) percent of the Contract Demand specified in section 4(a)(1).

(2) At the time schedules for the delivery of Peaking Replacement Energy are established by Riverside pursuant to section 11, Bonneville may limit the delivery rate for Peaking Replacement Energy to not less than sixty (60) percent of the then applicable Contract Demand.

(3) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Peaking Replacement Energy, including down to zero (0).

(4) To the extent that Bonneville restricts the delivery of Peaking Replacement Energy, Bonneville may (i) place such energy into the Energy Account as described in section 7; or (ii) the Parties may agree to delay the delivery of such energy.

7. Energy Account.

(a) Bonneville shall maintain the Energy Account. The Energy Account shall contain monthly amounts of Peaking Replacement Energy and Exchange Energy which has not been delivered to Bonneville due to either limitations by Bonneville pursuant to sections 4(c) and 6(b) or transmission limitations pursuant to section 8(c).

(b) Subject to section 7(b)(1), Bonneville may withdraw energy from the Energy Account during a Calendar Week by providing Riverside with notice by 1400 hours on the Thursday prior to such Calendar Week, specifying the weekly quantity of energy to be withdrawn, and the rate(s) of delivery for such energy. Unless otherwise mutually agreed, the rate(s) of delivery shall not exceed the

then applicable Contract Demand and the times of delivery shall be those hours other than (i) 0800 to 2200 hours Monday through Friday, excluding holidays, during the period November 1 through April 30; and (ii) 0900 to 2300 hours Monday through Friday, excluding holidays, during the period May 1 through October 31. Energy withdrawn from the Energy Account shall be withdrawn on a first-in-first-out basis.

(1) Unless otherwise agreed, Bonneville may not withdraw more than 1800 MWH from the Energy Account in any Calendar Week. Such withdrawals shall not cause Riverside to defer or otherwise limit deliveries of Firm Peaking Capacity, Firm Peaking Energy, Exchange Energy or Peaking Replacement Energy. Riverside shall deliver energy as requested pursuant to section 7(b) during the Delivery Season from the Energy Account, subject to forced outages. Except as provided in sections 7(b)(2) and 7(b)(3), withdrawals from the Energy Account at times other than during the Delivery Season shall be by agreement of the Parties' schedulers.

(2) Bonneville at its option, may extend the Delivery Season to April 30 and, subject to the provisions of this section 7, schedule energy from the Energy Account during the appropriate light load hours specified in this section 7(b). Any remaining balance in the Energy Account will be delivered pursuant to the provisions of this section 7, or cashed out pursuant to section 7(c).

(3) After April 30, and at Bonneville's request, the Parties shall attempt in good faith to develop a mutually agreeable plan for the delivery of any energy remaining in the Energy Account pursuant to section 8(c). If the Parties are unable to agree on a plan, and such energy is not delivered

by July 31, the energy shall be cashed out at the rate specified in section 7(c).

(c) Each August 1, energy remaining in the Energy Account shall be cashed out at the cash-out price in effect at the time such energy was entered into the Energy Account. The cash-out price for such energy is Bonneville's average cost of nonfirm energy, as calculated in Bonneville's rate cases. Riverside shall be relieved of any obligation to provide energy to Bonneville to the extent the energy is cashed out.

8. Transmission Limitations.

(a) In the event of an interruption of deliveries by either Party due to a Total Outage or a Partial Outage, transactions under this Agreement will have priority over (i) any competing nonfirm energy transaction of Riverside and Bonneville and (ii) any firm transactions providing for a capacity sale or a capacity for energy exchange under agreements executed after the date of execution of this Agreement.

(b) Following periods of Partial Outage or Total Outage, Riverside shall continue to be obligated to deliver Peaking Replacement Energy and Exchange Energy. Both Parties shall use best efforts to reschedule interrupted or curtailed deliveries of Peaking Replacement Energy and Exchange Energy under conditions approximately equivalent to the conditions existing prior to the Partial Outage or Total Outage; provided, that in rescheduling Peaking Replacement Energy and Exchange Energy, Riverside shall not exceed the delivery limits set forth in sections 4(c) and 6(b), unless otherwise agreed. The Parties may also agree to reschedule delivery at other times and under conditions other than those existing prior to the Partial Outage or Total Outage.

(c) Peaking Replacement Energy and Exchange Energy shall be rescheduled within sixty (60) days following the end of the Partial Outage or Total Outage, unless the Parties otherwise mutually agree. To the extent the Parties have not so rescheduled such energy, the Energy Account shall be credited for any such amounts of Peaking Replacement Energy and Exchange Energy, with an effective date of the first day after the end of the Partial Outage or Total Outage.

(d) Exchange Energy Relief.

(1) In the event that (i) there has been more than three hundred (300) hours of Total Outages during the Summer Season; and (ii) Bonneville has elected not to purchase Exchange Energy pursuant to section 8(f); and (iii) deliveries of Firm Peaking Energy, which the Parties reasonably expect would have been delivered but for the occurrence of Total Outages in excess of three hundred (300) hours, have not been rescheduled, then Riverside shall be excused from delivering a proportional amount of Exchange Energy determined pursuant to section 8(d)(2). For any partial Summer Season deliveries of Firm Peaking Capacity hereunder, a pro-rated sum of Total Outages based on three hundred (300) hours shall be used.

(2) A ratio shall be calculated, the numerator shall be the number of hours of Total Outages in the Summer Season exceeding three hundred (300), and the denominator shall be the number of hours in the Summer Season. This ratio shall then be multiplied by the exchange ratio and the resultant product subtracted from the exchange ratio to determine the amount of Exchange Energy which Riverside shall be obligated to deliver to Bonneville.

(e) Firm Peaking Capacity Sale Relief.

(1) In the event that (i) there has been more than four hundred twenty hours (420) hours of Total Outages during the Winter Season; and (ii) deliveries of Firm Peaking Energy, which the Parties reasonably expect would have been delivered but for the occurrence of Total Outages in excess of four hundred twenty (420) hours, have not been rescheduled, then Riverside shall receive a capacity payment credit determined pursuant to section 8(e)(2). For any partial Winter Season sale hereunder, a pro-rated sum of Total Outages based on the four hundred twenty (420) hours shall be used,

(2) For each Total Outage, following the occurrence of a relief condition described in section 8(e)(1), Riverside shall receive a capacity payment credit for the duration of such Total Outage. The capacity payment credit shall be calculated by determining the duration of such Total Outage during the billing month, divided by the total number of hours in that month. The resultant factor shall be multiplied by the demand charge per kilowatt-month, multiplied by the applicable Contract Demand for the month to determine the capacity payment credit.

(f) Bonneville Purchase of Exchange Energy.

Bonneville may elect to purchase Exchange Energy which Riverside otherwise would be excused from delivering pursuant to section 8(d) as follows:

(1) Bonneville shall notify Riverside at least one (1) month prior to requesting delivery of such Exchange Energy.

(2) Within ten (10) Workdays after receipt of Bonneville's notice requesting Exchange Energy, and prior to Riverside committing to obtain Exchange Energy, Riverside shall inform Bonneville of the probable lowest cost resources available to supply such requested Exchange Energy, including the estimated Total Incremental Cost of such resources. Riverside shall revise the Total Incremental Cost if conditions change substantially.

(3) Bonneville shall provide Riverside with at least one (1) Calendar Week's final written notice prior to the start of each Calendar Week's deliveries whether Bonneville shall require Riverside to deliver the Exchange Energy, or whether Bonneville relieves Riverside of the obligation to deliver that Calendar Week's Exchange Energy.

(4) For all deliveries of Exchange Energy pursuant to this section 8(f), Bonneville shall pay Riverside the Total Incremental Cost of the Exchange Energy for the first three (3) months of deliveries, and one hundred fifteen (115) percent of Riverside's Total Incremental Cost for all Exchange Energy delivered after three (3) months pursuant to this section 8(f).

9. Points of Delivery.

Deliveries shall be at the point where the DC Intertie crosses the Nevada-Oregon border, or the point(s) where the 500 kV alternating current transmission line(s) between Oregon and California cross the California-Oregon border, or at such other points as agreed by the Parties.

10. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of Public Law 88-552 (the Northwest Preference Act) and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to Public Law 88-552, Bonneville shall have the right to restrict or terminate delivery of all or a portion of the capacity associated with the Firm Peaking Capacity sale on five (5) years written notice specifying the amounts and duration of the restriction, if such capacity is needed to meet the capacity requirements in the Pacific Northwest (as defined in Public Law 88-552). Such restrictions to Riverside shall be limited to the amounts and duration necessary to cover Bonneville's projected Pacific Northwest needs. The sale of capacity to Riverside under this Agreement shall continue in months during which such capacity is not needed, as determined by Bonneville, in the Pacific Northwest.

11. Scheduling Provisions.

Submission of all schedules between Bonneville and Riverside, or its agent, for delivery of capacity and energy hereunder shall be subject to the following provisions unless otherwise agreed by the Parties' schedulers or dispatchers, or their agents as designated by a Party to act on its behalf:

(a) Preschedules shall be completed by 0930 hours on each Workday and shall be effective for each hour of the following day, or days, through the next Workday.

(b) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts of Firm Peaking Energy that Riverside, or its agent, anticipates it will schedule from Bonneville each day for the following ten (10) days. Riverside, or its agent, shall

submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Riverside, or its agent, or Bonneville to schedule such amounts.

(c) Each Party, or its agent shall endeavor to avoid requesting changes in schedules. While changes in preschedules may be permitted in certain circumstances, requests for such changes in prescheduled amounts for any hour shall be only as agreed. Normally such changes shall be submitted no later than thirty (30) minutes before the hour for which the change is to be effective.

12. Payment.

(a) Riverside agrees to pay Bonneville in accordance with this Agreement upon receipt of bills sent by Bonneville. Bonneville shall render preliminary and final adjusted monthly bills to Riverside. Riverside shall pay Bonneville by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday, as observed by Riverside, then the due date shall be the next following business day. Payment of bills shall be in accordance with Exhibits A and B, attached hereto.

(b) Bonneville may offset any amount due Riverside pursuant to this Agreement by any amount due to Bonneville pursuant to both this Agreement and any other agreement between the Parties. Riverside may offset any amount due Bonneville pursuant to this Agreement by any amount due to Riverside pursuant to both this Agreement and any other agreement between the Parties. Such net billing shall accomplish timely payment.

13. Uncontrollable Forces.

(a) Obligations of the Parties, other than those to pay money under section 12, shall be excused when failure to perform such obligations is due to an Uncontrollable Force; provided, however, that the Parties shall seek remedies as set forth in section 16; and provided further, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability with reasonable dispatch. Nothing in this section 13 shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(b) Each Party shall notify the other as soon as possible of any Uncontrollable Force which may adversely affect performance under this Agreement. Failure of a Party to give notice to the other Party shall not be deemed a waiver of such Uncontrollable Force.

(c) If an Uncontrollable Force causes a Partial Outage or Total Outage, this section 13 shall not apply until one (1) Year after the commencement of the Partial Outage or Total Outage.

14. Assignment of Agreement.

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

15. Notices.

Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given, or made if delivered in person or sent by telegraph, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:

To Riverside: Public Utilities Director
City of Riverside
3900 Main Street
Riverside, CA 92522

To Bonneville: The Administrator
United States Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Either Party may, by written notice to the other Party, change the designations or address of the person so specified as the one to receive notices pursuant to this Agreement.

16. Disputes.

Pending resolution of the disputed matter, the Parties shall continue performance of their respective obligations pursuant to this Agreement. The Parties shall discuss disputes regarding any matter relating to this Agreement, and shall use their best efforts to amicably and promptly resolve each such dispute.

17. Audits.

Each Party shall reserve the right to audit and to examine any cost, payment, settlement or supporting documentation, including, but not limited to, audit reports, resulting from any items set forth in this Agreement. Any such Audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The Party being audited agrees to cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of five (5) years following the first billing for such cost under this Agreement. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period.

The Party being audited shall be notified in writing of any exception taken as a result of an audit promptly after completion of the audit. The Party being audited shall have thirty (30) days to review the notice of exception.

(a) If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) to the other Party, with interest calculated in the same manner as in Exhibits A and B, or their successors, within ten (10) days after agreement is reached.

(b) If the Parties dispute any exception(s) taken as a result of the audit, the owing Party shall so notify the other Party in writing promptly after its receipt of the written notification of exception. Such dispute shall then be subject to the provisions set forth in section 16. If upon resolution of the dispute, it is determined that a Party shall make payment to the other Party, such payment shall be made within ten (10) days of resolution of the dispute, with interest calculated in the same manner as set forth in Exhibits A and B, or their successors.

18. Governing Law.

This Agreement shall be interpreted, governed by and construed under Federal law applicable to Bonneville.

19. Waivers.

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement shall be waived except in writing. Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or with any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter.

20. Signature Clause.

The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Assistant Administrator

Date JUN 15 1990

CITY OF RIVERSIDE

By _____

Title Mayor

Date APR 27 1990

ATTEST:

By _____

Title City Clerk

Date APR 27 1990

APPROVED AS TO FORM
_____ 4/27
ASST. CITY ATTORNEY

(VS6-PMCE-4321c)

EXHIBIT A

1989 Wholesale Power Rate Schedules

and General Rate Schedule Provisions

Bonneville
POWER ADMINISTRATION

United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, Oregon 97232

Bonneville Power Administration's 1989 Wholesale Power Rate Schedules and General Rate Schedule Provisions, contained herein, were approved on an interim basis effective October 1, 1989. These rate schedules and provisions were approved by the Federal Energy Regulatory Commission, United States Department of Energy, in a Commission Order issued September 29, 1989 (Docket No. EF89-2011-000).

These rate schedules and provisions supersede in their entirety the Administration's Wholesale Power Rate Schedules and General Rate Schedule Provisions effective July 1, 1987.

WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

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SCHEDULE PF-89

PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, construction, test and start-up, and station service.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, Bonneville Power Administration (BPA) may make power available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule PF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule includes the Preference rate and the Exchange rate. The Preference rate is available for the general requirements of public body, cooperative and Federal agency customers and includes credit attributed to the provision of section 7(b)(2) of the Northwest Power Act. The Exchange rate is available for all purchases of residential and small farm exchange power pursuant to the Residential Purchase and Sale Agreements.

A. Preference Rate

1. Demand Charge

a. $3.46 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 18.4 mills per kilowatthour of billing energy for the billing months September through March;

b. 14.4 mills per kilowatthour of billing energy for the billing months April through August.

B. Exchange Rate

1. Demand Charge

a. $3.56 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 19.1 mills per kilowatthour of billing energy for the billing months September through March;

b. 15.1 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

In this section, billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), and metered requirements purchasers and those Priority Firm Power purchasers not covered by sections III.A and III.B (section III.C).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or

(2) the Measured Demand, before adjustment for power factor.

b. the lower of:

(1) the Computed Peak Requirement, or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 78 percent of the Measured Energy (excluding unauthorized increase), and

(2) 22 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 57 percent of the Measured Energy (excluding unauthorized increase), and

(2) 43 percent of the Computed Energy Maximum.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy

The billing energy shall be the energy associated with the utility's residential load for each billing period. Residential load shall be computed in accordance with the provisions of the purchaser's Residential Purchase and Sale Agreement.

C. Metered Requirements Purchasers, Other Purchasers Not Covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking or exchanging power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)

BPA shall apply a discount to the charges for all Priority Firm Power sold to purchasers who are eligible for an LDD. Eligibility for the LDD and the amount of the discount (3, 5, or 7 percent) shall be determined pursuant to section III.C.3 of the GRSPs.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Northwest Power Planning Council has recommended that a conservation surcharge be imposed on those customers subject to such surcharge as determined by the Administrator in accordance with BPA's Policy to Implement the Council-Recommended Conservation Surcharge. The Conservation Surcharge shall be applied pursuant to section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in sections II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the PF rates due to the Cost Recovery Adjustment Clause.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for

those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Priority Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

G. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of Priority Firm Power taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an unauthorized increase. BPA first shall determine the amount of unauthorized increase related to demand and shall treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, which exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

(1) to a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month which exceeds the amount of energy which the purchaser is contractually entitled to take during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

H. Coincidental Billing Adjustment

Purchasers of Priority Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

I. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the power sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's computed peak requirement and computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October;

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PF-89 rate is 78.5 percent FBS and 21.5 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE IP-89

INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for both the contract purchase of Industrial Firm Power and the purchase of Auxiliary Power if requested by the DSI customer and made available by BPA. If a DSI customer purchasing power under this rate schedule requests and BPA makes available power under another applicable wholesale rate schedule the IP-89 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The following rates shall be applied when first quartile service is provided under this rate schedule in accordance with the terms of a purchaser's Power Sales Contract dated August 25, 1981. A separate billing adjustment for the reserves provided by the purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the demand and energy charges.

Any contractual reference to the IP Premium Rate shall be deemed to refer to the demand and energy charges set forth below. Any reference to the IP Standard Rate shall be deemed to refer to the same demand and energy charges minus the Discount for Quality of Service.

A. Demand Charge

1. $4.14 per kilowatt of billing demand occurring during all Peak Period hours.
2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 19.5 mills per kilowatthour of billing energy for the billing months September through March;
2. 15.6 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

A. Billing Demand

The billing demand shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs). If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP-89 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C.3 of the GRSPs.

B. Billing Energy

The billing energy shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

However, if BPA has agreed to serve only a portion of the DSI's load under the IP rate schedule, the billing energy for the power purchased under the IP rate shall be specified in the contract initiating such arrangement.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Discount for Quality of First Quartile Service

1. Application and Amount of First Quartile Discount

If a purchaser requests discounted rate service, a discount of 0.6 mills per kilowatthour of billing energy shall be granted. This billing credit shall be applied to the monthly billing energy under section III.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section IV.D of this rate schedule.

2. Eligibility Requirements for First Quartile Discount

To qualify for the First Quartile Discount the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

B. Curtailments

BPA shall charge the DSI for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract. BPA shall apply the demand charge in effect at the time of the curtailment in the computation of the amount of the curtailment charge. In the event that a purchaser is found to be eligible to have a portion of their load served under an alternative rate schedule, application of the curtailment charge shall be specified in the contract instituting such arrangement.

C. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all power purchases under this rate schedule.

Application of the Cost Recovery Adjustment Clause shall result in a uniform adjustment applied to the demand and energy charges, contained in sections II.A and II.B of this rate schedule, and the first quartile discount, if applicable, contained in section IV.A.1 of this rate schedule.

The uniform percentage (CRAC%) determined in Section III.C.5.c. of the GRSPs shall be applied in the following manner:

$$(1 + \frac{CRAC\%}{100}) * \frac{22.8}{23.5}$$ times the demand, energy, and first quartile discount charges.

where: 22.8 represents the average IP-89 margin-based rate in mills per kilowatthour, and 23.5 represents the average IP-89 floor rate in mills per kilowatthour.

D. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

E. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the IP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE VI-87

VARIABLE INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for purchases under the Power Sales Contract implementing the Variable Industrial Power rate schedule (Variable Rate Contract) of: (1) Industrial Firm Power and (2) Auxiliary Power if requested by the DSI customer and made available by BPA. This schedule is available only for that portion of a DSI's load used in primary aluminum reduction including associated administrative facilities, if any. By virtue of incorporation of this rate schedule and associated General Rate Schedule Provisions (GRSPs) in the Variable Rate Contract, DSIs electing to purchase power under this rate schedule contractually agree to the terms and conditions of this rate schedule. A DSI further agrees to waive for that portion of their load designated to purchase power at the VI rate, all rights they might otherwise have to purchase power at the Industrial Firm Power Rate Schedule for the duration of the Variable Rate Contract. Section VI.J. supplements schedule VI-86. GRSPs effective July 1, 1985, as revised effective August 1, 1986, and as revised in the 1987 rate case and in subsequent wholesale rate filings are applicable to this rate schedule. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. TERM OF THE RATE

This rate schedule shall take effect on August 1, 1986, and shall terminate on midnight June 30, 1993, unless BPA elects to exercise its unilateral option to terminate the rate at midnight June 30, 1991. This termination right is described in section VI.E. of this rate schedule. Actions to invoke an early termination shall comply with section VI.E. of this rate schedule and with the provisions and stipulations set forth in the Variable Rate Contract.

SECTION III. RATE

A. Revised Rate Charges Subject to Rate Case Adjustments

The following rates shall apply to Industrial customers that meet the eligibility requirements and elect to purchase power under the Variable Industrial Power Rate Schedule. These rates shall remain in effect until the next Rate Adjustment Date, at which point the rates shall be adjusted following the procedures set forth in section VI.C. of this rate schedule, unless the Cost Recovery Adjustment Clause triggers, at which point the rates shall be adjusted following the procedures set forth in section VI.J. of this rate schedule. In addition, the Lower Rate Limit also will be subject to a biennial adjustment pursuant to section VI.B. of this rate schedule. The formula to be used in the calculation of the monthly power bill is contained in section IV. A separate billing adjustment for the value of the reserves provided by purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the Plateau Energy Charge.

1. Base Variable Industrial Rate

a. Demand Charge

$5.33 per kilowatt of billing demand occurring during the Peak Period. No demand charge is applied during Offpeak Period hours.

b. Plateau Energy Charge

16.1 mills per kilowatthour of billing energy.

2. First Quartile Service Discount

0.5 mills per kilowatthour of billing energy.

3. Lower Rate Limit

8.3 mills per kilowatthour of billing energy.

4. Upper Rate Limit

21.9 mills per kilowatthour of billing energy.

B. Initial Rate Parameters Subject to Annual Adjustments

The following rate parameters shall be used in determining the power bills for customers electing to purchase power under the Variable Industrial Power rate schedule. These parameters will be adjusted annually starting on July 1, 1987, and every July 1 thereafter, in accordance with the procedures contained in section VII.B. of the GRSPs.

1. Lower Pivot Aluminum Price

60.8 cents per pound.

2. Upper Pivot Aluminum Price

73.4 cents per pound.

SECTION IV. FORMULA

The Variable Industrial Power rate is a formula rate tied to the U.S. market price of aluminum. Under this rate schedule, the monthly energy charge varies in response to changes in the average price of aluminum in U.S. markets.

A. Demand Charge

1. The Demand Charge, as stated in section III.A.1.a. of this rate schedule, remains constant over all aluminum prices. The demand charge is applied to billing demand occurring during all Peak Period hours for all billing months.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. Plateau Energy Charge

When the monthly billing aluminum price (described in section VII.A. of the GRSPs) is between the Lower Pivot Aluminum Price and the Upper Pivot Aluminum Price inclusive (as stated in sections III.B.1. and III.B.2. of this rate schedule), the monthly energy charge shall be the Plateau Energy Charge as stated in section III.A.1.b. of this rate schedule.

2. Reductions to Plateau Energy Charge

When the monthly billing aluminum price is less than the Lower Pivot Aluminum Price, the monthly energy charge shall be the greater of:

a. The Plateau Energy Charge - (LP - MAP) * (LS)

where:

LP = the Lower Pivot Aluminum Price as stated in section III.B.1. of this rate schedule.

MAP = the monthly billing aluminum price in cents per pound determined pursuant to section VII.A. of the GRSPs

LS = lower slope = $\frac{\text{1 mill per kilowatthour}}{\text{1 cent per pound}}$

or

b. the Lower Rate Limit as stated in section III.A.3. of this rate schedule.

3. Increases to Plateau Energy Charge

When the monthly billing aluminum price is greater than the Upper Pivot Aluminum Price, the monthly energy charge shall be the lesser of:

a. The Plateau Energy Charge + (MAP - UP) * (US)

where:

MAP = the monthly billing aluminum price in cents per pound, as determined according to section VII.A. of the GRSPs.

UP = the Upper Pivot Aluminum Price as stated in section III.B.2. of this rate schedule.

US = upper slope = $\frac{\text{0.75 mills per kilowatthour}}{\text{1 cent per pound}}$

or

b. the Upper Rate Limit, as stated in section III.A.4. of this rate schedule.

SECTION V. BILLING FACTORS

A. Billing Demand

1. Billing Demand for Customers Whose Entire BPA Load is Served at the Variable Industrial Power Rate

The billing demand for power purchased shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10. of the GRSPs.

2. Billing Demand for Customers When Only a Portion of Their Total BPA Load is Served at the Variable Rate

The Billing Demand shall be the portion of the BPA Operating Level attributable to the VI rate as determined by the method specified in the Variable Rate Contract.

3. Billing Demand During Periods of Transitional Service

If BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C. of the GRSPs.

B. Billing Energy

The billing energy for power purchased shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

SECTION VI. OTHER ADJUSTMENTS AND SPECIAL PROVISIONS

A. Lower and Upper Pivot Aluminum Prices

Effective July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices set forth in section III.B. of the rate schedule shall be adjusted following the procedures set forth in section VII.B. of the GRSPs. The adjusted Lower and Upper Pivot Aluminum Prices shall supersede the Lower and Upper Pivot Aluminum Prices contained in section III.B. of the rate

schedule. The revised Lower and Upper Pivot Aluminum Prices shall be used for billing purposes and subsequent adjustments to the Lower and Upper Pivot Aluminum Prices.

B. Lower Rate Limit

Beginning with the July 1, 1988, annual adjustment date and every second July 1 thereafter, the Lower Rate Limit as stated in section III.A.3. shall be increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall supersede the Lower Rate Limit as stated in section III.A.3. of the rate schedule. This increase is in addition to rate adjustment increases in the Lower Rate Limit described in section VI.C. of this rate schedule. In the event that a rate adjustment date and the annual adjustment date occur simultaneously, the Lower Rate Limit shall be adjusted first for changes in the Plateau Energy Charge pursuant to section VI.C. of this rate schedule, and then increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall be used for billing purposes and subsequent rate adjustments.

C. Rate Adjustments

The overall rate level of this rate shall be subject to adjustment in BPA's general wholesale power rate case following the procedures and directives of the Northwest Power Act. The overall rate level consists of the Demand Charge, Plateau Energy Charge, and First Quartile Service Adjustment contained in sections III.A.1. and III.A.2.; these shall be adjusted by a uniform percentage based on the percentage change in the overall rate level. The Lower and Upper Rate Limits as stated in sections III.A.3. and III.A.4. of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, in the Plateau Energy Charge. The Lower and Upper Pivot Aluminum Prices shall not be adjusted in the rate case; rather, they shall be adjusted pursuant to the procedures described in section VII.B. of the GRSPs. The lower and upper slopes shall not be adjusted. The rate for unauthorized increase shall be separately determined in each rate case.

D. Discount for Quality of First Quartile Service

If a purchaser requests First Quartile service with other than Surplus FELCC, a discount contained in section III.A.2. of this rate schedule shall be granted. This billing credit shall be applied to the monthly billing energy under section V.B. for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section VI.G. of this rate schedule. To qualify for the First Quartile Discount, the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

E. Termination Provision

The Administrator may terminate the Variable Industrial Power rate effective midnight June 30, 1991, upon a determination that significant changes in the conditions and expectations under which this rate was offered render the continuation of the Variable Industrial rate inconsistent with BPA's stated goals and objectives. BPA shall provide notification of such a determination pursuant to the provisions of the Variable Rate Contract. As part of the notification procedures, BPA shall provide a reasonable opportunity for interested parties to comment on BPA's determination, as well as to examine the comments submitted by other parties, prior to BPA taking final action to cancel the rate. If BPA determines that the Variable Industrial rate will remain in place until midnight June 30, 1993, BPA shall provide notice that so states and no additional action by BPA will be required.

F. Curtailments

BPA shall charge the customer for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract and the provisions contained in the Variable Rate Contract.

G. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

H. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1. of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the BPA Operating Level by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

I. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI

to whom BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2. of the GRSPs.

J. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5. of the GRSPs shall be applied to all power purchases under this rate schedule consistent with the procedures to adjust the Variable Industrial rate and the provisions of the Variable Rate Contract. A uniform adjustment will be made only if it causes demand and Plateau Energy charges and the First Quartile Service Discount to increase.

The uniform percentage (CRAC%) determined in section III.C.5.c. of the GRSPs shall be applied in the following manner:

$(1 + \frac{CRAC\%}{100}) \cdot \frac{22.4}{23.0}$ times the demand and Plateau Energy charges contained in section III.A.1. of this rate schedule and to the First Quartile Service Discount specified in section III.A.2. of this rate schedule.

where: 22.4 represents the average VI-89 margin-based plateau rate in mills per kilowatthour, and 23.0 represents the average VI-89 floor rate in mills per kilowatthour.

The Lower and Upper Rate Limits stated in sections III.A.3. and III.A.4. of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, to the Plateau Energy charge due to application of the Cost Recovery Adjustment Clause. The adjusted rate parameters shall be used for billing purposes and supersede the rate charges subject to the adjustment contained in section III.A. of this rate schedule. The adjusted rate parameters shall also be used in subsequent rate adjustments pursuant to section III.B. of this rate schedule and to subsequent biennial adjustments to the lower rate limit pursuant to section VI.B. of this rate schedule.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the VI-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SI-89

SPECIAL INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available to any DSI purchaser using raw minerals indigenous to the region as its primary resource and qualifying for this special power pursuant to the procedures established in section 7(d)(2) of the Northwest Power Act. This schedule is available for the contract purchase of this special class of industrial power and also for the purchase of Auxiliary Power if requested by the DSI and made available by BPA. The Special Industrial Offpeak rate available for Hanna Nickel Smelting Company pursuant to the Amendatory Agreement executed July 1, 1985, remains in force and is retained herein. Except for the Special Industrial Offpeak rate, schedule SI-89 supersedes schedule SI-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule contains the Standard Special Industrial Power Rate and the Special Industrial Offpeak Rate. The Standard Special Industrial Power Rate is available to any qualifying DSI for full service provided during all hours of the day. The Special Industrial Offpeak Rate is a lower rate available to the Hanna Nickel Smelting Company (Hanna) for service during periods specified by BPA. A separate billing adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power is not contained in the rate schedule; the adjustment is reflected in the Standard Special Industrial Power Rate.

A. Standard Special Industrial Power Rate

1. Demand Charge

a. $3.08 per kilowattmonth of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 16.9 mills per kilowatthour of billing energy for the billing months September through March;

b. 12.9 mills per kilowatthour of billing energy for the billing months April through August.

B. Special Industrial Offpeak Rate

1. Demand Charge

No demand charge in any hour of the day.

2. Energy Charge

7.0 mills per kilowatthour of billing energy during all billing months.

SECTION III. BILLING FACTORS

A. Billing Demand

1. Standard Special Industrial Power Rate

The billing demand for power purchased under the Standard Special Industrial Power Rate shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the Peak Period BPA Operating Levels for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs).

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Special Industrial Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

2. Special Industrial Offpeak Rate

There is no billing demand for purchases under the Special Industrial Offpeak rate.

B. Billing Energy

The billing energy under both the Standard Special Industrial and Special Industrial Offpeak Rates shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

The kilowatthours of billing energy shall be prorated among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE SI-89 RATE FOR THE HANNA NICKEL SMELTING COMPANY

All purchasers, except for Hanna, shall purchase power under the Standard Special Industrial Power rate. Hanna shall have the option to select one of two types of service,

standard service or offpeak service. In this case, BPA will provide standard service under the Standard Special Industrial Power Rate and offpeak service under the Special Industrial Offpeak Rate. Unless BPA receives a formal request from Hanna for service under the Special Industrial Offpeak Rate, all service will be standard service provided under the Standard Special Industrial Power Rate. To change the type of service provided and the associated rate, Hanna shall submit a formal request for service under the preferred rate option in accordance with the terms of the power sales contract providing for purchases under this rate schedule. Once Hanna has elected to purchase under one of the two options, all purchases of Special Industrial Power shall be subject to the terms and conditions of that rate option until such time that Hanna requests the other type of service.

SECTION V. SERVICE UNDER THE SPECIAL INDUSTRIAL OFFPEAK RATE

BPA shall designate the hours during which offpeak service will be available, and shall provide at least 2 weeks' notice before changing those designated hours. BPA shall identify at least 10 and up to 13 hours on each day Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday, during which offpeak service will be available to the purchaser.

If Hanna has elected to be served under the Special Industrial Offpeak Rate, Hanna may request, during the designated offpeak periods, service in an amount not to exceed the purchaser's Contract Demand. During all other hours Hanna shall curtail service to a level not to exceed 15 percent of Contract Demand.

SECTION VI. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Curtailments

BPA shall charge the DSI for curtailments in accordance with the provisions of the DSI's power sales contract. Any curtailment charge levied shall be computed using the Standard Special Industrial Power Rate.

B. Unauthorized Increase Charge

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

If BPA is providing service to Hanna under the Special Industrial Offpeak Rate, the amount by which Hanna's Measured Demand exceeds 15 percent of its Contract Demand during any hour other than the specified special hours shall be considered unauthorized increase.

C. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment for service under the Standard Special Industrial Power Rate, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. For service under the Special Industrial Offpeak Rate, BPA shall increase the billing energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

D. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Special Industrial Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. In addition, no credit shall be applied to purchases under the Special Industrial Offpeak Rate. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

E. Extended Service Provision

The terms of this rate schedule may be extended for a period not to exceed June 30, 1990, in accordance with the Amendatory Agreement effective July 1, 1985, with the Hanna Nickel Smelting Company (Hanna). The Amendatory Agreement contains Hanna's agreement to make certain investments in a wet screening process at its Riddle facility.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SI-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CF-89

FIRM CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of Firm Capacity without energy on a Contract Demand basis. This schedule is available only to those purchasers holding Firm Capacity contracts executed prior to July 1, 1985. It supersedes Schedule CF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

$42.48 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.54 per kilowattmonth of Contract Demand.

SECTION III. BILLING FACTORS

The billing demand shall be the Contract Demand.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the General Rate Schedule Provisions (GRSPs) and subsequent to any other rate adjustments.

B. Extended Peaking Surcharge

The monthly capacity rate specified in section II above shall be increased by the following extended peaking surcharge to compensate BPA for each hour that the purchaser's monthly demand duration exceeds 8 hours:

1. $0.0908 per kilowatt per hour of extended peaking for the months April through October;
2. $0.0512 per kilowatt per hour of extended peaking for the months November through March.

The charge shall be adjusted pro rata for each portion of an hour of extended peaking supplied to the purchaser.

The purchaser's monthly demand duration shall be determined by dividing:

1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the day of maximum kilowatthour use during those hours, provided such day is not a Sunday, by
2. the purchaser's Contract Demand for such month.

The purchaser's extended peaking shall be the amount by which the purchaser's monthly demand duration exceeds 8 hours. The extended peaking surcharge shall not be applied during periods when BPA does not require the delivery of peaking replacement energy by the purchaser.

C. Energy Return Surcharge

The energy associated with the delivery of Firm Capacity must be returned to BPA in accordance with the terms of the purchaser's Firm Capacity Contract. Unless waived by BPA, any purchaser whose energy returns during any single hour exceed 60 percent of the purchaser's Contract Demand during any single hour shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months April through October, and
2. 1.48 mills per kilowatthour for the months November through March.

D. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases under this rate schedule. The percentage increase calculated in sections III.C.5.c of the GRSPs shall be applied to the demand charges contained in section II of this rate schedule.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CF-89 rate is 75.1 percent FBS and 24.9 percent Exchange for contract year service.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CE-89

EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of capacity:

A. when an emergency exists on the purchaser's system, or

B. when the purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser's load, provided the purchaser requests such capacity and BPA has capacity available for such purpose.

This schedule supersedes Schedule CE-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. **Demand Charge**

$1.06 per kilowatt of demand per calendar week or portion thereof.

B. **Intertie Charge**

The demand charge specified above shall be increased by $0.15 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS

The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar week. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, the billing demand for that week shall be the lower demand which BPA is able to supply.

SECTION IV. BILLING PERIOD

Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CE-89 rate is 75.1 percent FBS and 24.9 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NR-89

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers, direct consumption, or use in construction, test and start up, and station service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load. In addition, BPA may make this rate available to those parties participating in exchange agreements that use this rate schedule as the basis for determining the amount or value of power to be exchanged. This schedule supersedes Schedule NR-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $4.13 per kilowatt-month of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 25.5 mills per kilowatthour of billing energy for the billing months September through March;

2. 21.2 mills per kilowatthour of billing energy for the billing months April through August;

SECTION III. BILLING FACTORS

In this section billing factors are listed for computed requirements purchasers (section III.A) metered requirements purchasers, and those purchasers not covered by section III.A. (section III.B.).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this section.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement;

(2) the Measured Demand, before adjustment for power factor; or

b. the lower of:

(1) the Computed Peak Requirement; or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 56 percent of the Measured Energy, and

(2) 44 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 39 percent of the Measured Energy, and

(2) 61 percent of the Computed Energy Maximum.

B. Metered Requirements Purchasers and Other Purchasers Not Covered By Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract. However, purchasers who previously used the Firm Energy rate schedule, FE-2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in section II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the NR rates due to the Cost Recovery Adjustment Clause.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of New Resource Firm Power taking demand and/or energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase. BPA shall first determine the amount of unauthorized increase related to demand and shall then treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, that exceeds the demand which the purchaser is contractually entitled to take during the billing month and that cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy which the purchaser is contractually entitled to take during that month and that cannot be assigned:

(1) to a class of power that BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

F. Coincidental Billing Adjustment

Purchasers of New Resource Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

G. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during the billing month due to an outage on the facilities used by BPA to deliver New Resource Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

H. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the Power Sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's estimated computed peak requirement and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October, and
2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the NR-89 rate is 100.0 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SP-89

SHORT-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Surplus Firm Power for the period ending September 30, 1994, including purchases under the Western Systems Power Pool (WSPP) agreements. BPA is not obligated to make power or energy available under this rate schedule if such power or energy would displace sales under the IP-89, VI-87, PF-89, or NR-89 rate schedules. Schedule SP-89 supersedes schedule SP-87 and associated GRSPs, except in the case of contracts for sales under schedule SP-87 which become effective on or before September 30, 1989. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Contract Rate

1. Demand Charge

a. For contracts that specify 12 months of service per year, $51.48 per kilowatt per year of Contract Demand billed monthly at the rate of $4.29 per kilowatt of Contract Demand occurring during all Peak Period hours in each billing month.

b. For contracts that specify service for fewer than 12 months per year, the monthly demand charge shall be assessed only for the specified service months at the rate of $4.29 per kilowatt of Billing Demand occurring during the Peak Period plus:

$$\frac{\$4.29\ (12 - \text{specified service months})\ .25}{\text{specified service months}}$$

c. No demand charge during Offpeak Period hours

2. Energy Charge

24.3 mills per kilowatthour of Billing Energy.

B. Flexible Rate

Energy charges or demand and energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the purchaser. In no case shall the rate exceed 100 percent of the fixed and variable unit costs of generation and transmission of BPA's highest cost resource including exchange resources. No resource cost determination is needed for sales at less than or equal to the Contract rate.

C. Intertie Charge

Rates in sections II.A and II.B that equal or exceed the Contract rate shall be increased by the following charges for transactions over the Pacific Northwest-Pacific Southwest Intertie.

1. $.36 per kilowatt per month of billing demand and

2. 0.69 mills per kilowatthour of billing energy.

Rates in section II.B having an energy-only charge that equals or exceeds 30.2 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for transactions over the Pacific Northwest-Pacific Southwest Intertie.

SECTION III. BILLING FACTORS

The billing factors shall be the Measured Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for Short-Term Surplus Firm Power on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the SP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE MSL-87

MODIFIED LONG-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is effective December 1, 1988, and is available for the long-term purchase of Surplus Firm Power for use within the Pacific Northwest Region under BPA contracts executed on or before October 1, 1990. This rate schedule shall be offered for an amount of purchases not to exceed 1,350 MW peak and 572 MW average, less long-term purchases of Surplus Firm Power, exclusive of any surplus firm capacity sales, sold under other rate schedules pursuant to contracts executed after July 1, 1988. This rate schedule shall not be available for contracts that obligate BPA to acquire energy resources to support the sale. Sales of surplus firm energy under this rate schedule will not be included as a firm load in BPA's long-term resource planning. For contracts executed on or before October 1, 1990, this rate schedule shall continue in effect for 20 years from the date of execution of such contract, but in no event later than September 30, 2010. This rate schedule shall not be available for contracts executed after October 1, 1990. Schedule SL-87 supersedes schedule FD-85 and associated GRSP's. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The rate for the long-term purchase of Surplus Firm Power shall be mutually agreed to by BPA and the purchaser, provided that the present value of the forecasted revenue under the contract rate, as projected for the contract term at the date of contract execution, shall be equal to or greater than the forecasted revenue under the Floor projection, specified in subsection A below, and less than or equal to the forecasted revenue under the Ceiling projection, specified in subsection B below. The floor and ceiling projections filed with the Federal Energy Regulatory Commission on September 30, 1988, are incorporated by reference in this rate schedule and shall apply to all contracts executed under this rate schedule.

A. Floor Projection

1. Firm Power Sale

The Floor projection shall be the greater of BPA's average Priority Firm rate or BPA's opportunity cost of surplus firm power projected for each year of the contract term. The average PF rate shall be calculated at the load factor of the proposed sale.

2. Firm Capacity Sale

The Floor projection shall be the Priority Firm demand charge projected for each year of the contract term.

3. Combination Firm Power and Firm Capacity Sale

The floor projection shall be the sum of:

a. the floor in section A.1. for each year in which the purchase is a firm power sale; and

b. the floor in section A.2. for each year in which the purchase is a firm capacity sale.

B. Ceiling Projection

1. Firm Power Sale

The ceiling projection shall be the fully-allocated cost of BPA's highest cost resource including transmission costs projected for each year of the contract term.

2. Firm Capacity Sale

The ceiling projection shall be the demand component of BPA's highest cost resource including transmission costs projected for each year of the contract term.

3. Combination Firm Power and Firm Capacity Sale

The ceiling projection shall be the sum of:

a. the ceiling in section B.1. for each year in which the purchase is a firm power sale; and

b. the ceiling in section B.2. for each year in which the purchase is a firm capacity sale.

SECTION III. BILLING FACTORS

The billing factors shall be the Contract Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Escalation Requirement

Adjustments to the contract rate shall occur on the dates specified in the contract but the intervals between adjustment dates shall not exceed five years. Each contract shall include an escalation provision specifying the specific formula and index for escalating the contract rate over the term of the contract as mutually agreed to by the parties. In addition each contract shall specify a minimum escalator based on either changes in BPA's Priority Firm Power rate or changes in BPA's Average System Cost.

1. For the first five years, the minimum escalator may be based on:

   (a) the forecasted changes in BPA's Priority Firm Power rate or in BPA's Average System Cost at the date of contract execution, filed with the Federal Regulatory Commission on September 30, 1988; or

   (b) actual changes in BPA's Priority Firm Power rate or in BPA's Average System Cost determined in accordance with either subsection 3(a) or 3(b) below.

2. For every rate adjustment date after year five, the minimum escalator shall be based on actual changes determined in accordance with either subsection 3(a) or 3(b) below.

3. The minimum escalation for a contract will be calculated as follows:

   (a) Escalation Based on BPA's Priority Firm Power Rate

   To determine the change in BPA's Priority Firm Power rate the average Priority Firm Power rate or successors rate(s) in mills per kilowatthour in effect on the rate adjustment date specified in the contract shall be divided by average Priority Firm Power rate or successors rate(s) in mills per kilowatthour in effect on the date contract purchases began under this rate schedule. The average PF rate or successor rate(s) shall be calculated at the load factor of the proposed sale, and assume a uniform demand in all months. If there is more than one PF rate in effect, the PF rate shall be determined by a weighting based on forecasted sales in the relevant rate case.

   (b) Escalation Based on BPA's Average System Cost

   Changes in BPA's Average System Cost shall be calculated by dividing BPA's Average System Cost in effect on the rate adjustment date specified in the contract by BPA's Average System Cost in effect on the date contract purchases began under this rate schedule. For purposes of this rate schedule, BPA's Average System Cost shall be determined by dividing BPA's total system costs by BPA's total system sales. BPA's total system costs and total system sales are defined in section IV.D. of the GRSPs.

B. Early Termination Charge

If BPA and a purchaser agree to a rate where in each year of the contract the cumulative present value of the projected contract revenues through that year is not equal to or greater than the cumulative present value revenues at the floor projection as specified in section II.A. and the purchaser has an option to terminate the sale, the purchaser shall be subject to an early termination charge. Such a charge shall be greater than or equal to the difference between the floor revenues projected for that sale at the time the contract was executed and the contract revenues in each year over the period beginning from the date purchases began through the termination date with interest compounded quarterly, as determined by BPA's Office of Financial Management. Interest will continue to apply to any remaining balance until the total termination charge obligation is satisfied. The termination charge shall be payable in a lump sum within 30 days after the date the sale terminates unless an alternative payment schedule is otherwise mutually agreed to by BPA and the purchaser. Any late payment shall be subject to an additional late payment charge in accordance with section VI.G.4. of the GRSPs.

C. Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for the long-term purchase of Surplus Firm Power [and Firm Displacement Power] on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSP's). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the MSL-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NF-89

NONFIRM ENERGY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. This schedule also applies to energy delivered for emergency use under the conditions set forth in section V.A of the General Rate Schedule Provisions (GRSPs). BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. Schedule NF-89 supersedes Schedule NF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The average cost of nonfirm energy is 18.0 mills per kilowatthour. The NF-89 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost. All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap defined in section IV.C of the GRSPs.

A. Standard Rate

The Standard rate is any offered rate not to exceed 21.6 mills per kilowatthour.

B. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

C. Incremental Rate

The Incremental rate is the Incremental Cost of energy plus 2.0 mills per kilowatthour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

D. Contract Rate

The Contract rate is 14.9 mills per kilowatthour of billing energy.

SECTION III. ADJUSTMENTS TO RATES

A. Guaranteed Delivery Surcharge

A surcharge of 2.0 mills per kilowatthour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

B. Intertie Charge

Rate offers, under any of the rates specified above, greater than or equal to 18.0 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie.

SECTION IV. BILLING FACTORS

The billing energy for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

SECTION V. APPLICATION AND ELIGIBILITY

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or a combination of these rates may be in effect.

A. Standard Rate

The Standard rate:

1. is available for all purchases of nonfirm energy; and
2. applies to nonfirm energy purchased pursuant to the Relief from Overrun Exhibit to the power sales contract.

B. Market Expansion Rate

1. Application of the Market Expansion rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. have a displaceable resource, displaceable purchase of electricity, or

b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:

a. shutdown or reduction of the output of the displaceable resource in an amount equal to the amount of Market Expansion rate energy purchased; or

b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion rate

a. When only one Market Expansion rate is offered:

Purchasers qualifying under section V.B.2. who purchased nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.0 mills per kilowatthour.

b. When more than one Market Expansion rates are offered:

Purchasers qualifying under section V.B.2. who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying alternative fuel source is lower than the Standard rate plus 4.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below purchaser's qualifying decremental cost minus 4.0 mills per kilowatthour.

C. Incremental Rate

The Incremental rate applies to sales of energy:

1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;

2. that BPA may at its option not produce or purchase; and

3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) less 2.0 mills per kilowatthour.

D. Contract Rate

The Contract rate applies to contracts (except power sales contracts offered pursuant to sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. for the sale of nonfirm energy; or

2. for determining the value of energy.

E. Western Systems Power Pool Transactions

BPA may make available nonfirm energy for transactions under the Western Systems Power Pool (WSPP) agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and shall be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside that agreement.

F. End-User Rate

BPA may agree to a rate or rate formula for nonfirm energy purchases by end-users. Such rate or rate formula shall be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION VI. DELIVERY

A. Rate of Delivery

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. Guaranteed Delivery

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis.

Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation or transmission losses.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the average cost of nonfirm energy is 99.6 percent FBS and 0.4 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SS-89

SHARE-THE-SAVINGS RATE

SECTION I. AVAILABILITY

This rate schedule is available for the contract purchase of Nonfirm Energy under an experimental rate and is limited to the term of the rate experiment. Nonfirm Energy will be made available under this rate schedule for use both inside and outside the United States for the displacement of a qualifying resource, displaceable purchase of electricity, or end-user load that can be served with alternate fuel sources. This rate schedule is only available to purchasers who execute a contract with BPA specifying use of the Share-the-Savings Rate. BPA is not obligated to offer Nonfirm Energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. Schedule SS-89 supersedes Schedule SS-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The rate shall be a formula rate based solely or in part on decremental cost information submitted by the purchaser. The rate formula and decremental cost, for purposes of establishing charges under this rate schedule, shall be defined in the applicable contract. The rate formula agreed upon by BPA and the purchaser shall in no event result in a rate higher than the NF Rate Cap defined in section IV.C. of the GRSPs or lower than 1 mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing energy for Nonfirm Energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified in the Share-the-Savings Rate contract.

SECTION IV. APPLICATION AND ELIGIBILITY

A. General Requirements

In order to purchase Nonfirm Energy under the Share-the-Savings Rate, the purchaser must:

1. have executed a contract specifying application of the Share-the-Savings Rate Schedule.
2. have a displaceable resource, displaceable purchase of electricity, or be an end-user load with a displaceable alternate fuel source. End-user loads with alternate fuel sources may not use the Decremental Cost of a displaceable purchase of electricity to qualify for this rate.

B. BPA Service Priority

Offers of Nonfirm Energy under this rate schedule shall be made pursuant to the terms and conditions set forth in the Share-the-Savings rate contract. BPA will sell Nonfirm Energy under this rate schedule consistent with regional and public preference.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SS-89 rate is not based on the cost of BPA resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE RP-89

RESERVE POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of power:

A. in cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied;

B. for which BPA determines no other rate schedule is applicable; and

C. to serve a purchaser's firm power load in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States. This rate schedule supersedes Schedule RP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $3.64 per kilowatt of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

25.3 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

A. Billing Demand

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

B. Billing Energy

The billing energy shall be the Contract Demand multiplied by the number of hours in the billing month, if use of the Contract Demand for determining billing energy is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

SECTION IV. POWER FACTOR ADJUSTMENT

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The RP-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

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SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 1989 rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request FERC approval effective October 1, 1989. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for two years: PF-89, IP-89, SI-89, CE-89, CF-89, NR-89, SS-89, NF-89, and RP-89. The VI-87 rate schedule reflects adjustments of and supplements to the rate schedule VI-86 and associated GRSPs (which are to be in effect for 7 years). Sections III.A and VI.J of the VI-87 rate schedule are to be in effect for an additional 2 years. BPA proposes that rate schedule SI-89 be effective 2 years, except for the Special Industrial Offpeak rate provision, which is to remain in effect through June 30, 1990, pursuant to an Amendatory Agreement between BPA and Hanna Nickel Smelting Company executed July 1, 1985.

BPA proposes that the SP-89 rate schedule, and the GRSPs associated with this schedule, be effective for 5 years. BPA proposes that the Nonfirm Energy Rate Cap be effective for 12 years. BPA proposes that the MSL-87 and the GRSPs associated with this schedule be effective December 1, 1988, for contracts executed on or before October 1, 1990.

B. General Provisions

These 1989 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA's 1987 rate schedules (which became effective October 1, 1987) to the extent stated in the Availability section of each 1989 rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Northwest Power Act. All sales of power made under these rate schedules are subject to the following acts as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Northwest Power Act.

SECTION II. TYPES OF BPA SERVICE

A. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for resale to ultimate consumers, or for direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies. (Construction, test and start-up, and station service are defined in section V.B of these GRSPs.)

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount or value of power to be exchanged.

Power purchased under the power rate schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

Priority Firm Power is not available to serve New Large Single Loads.

B. New Resource Firm Power

New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:

1. for any New Large Single Load,
2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and
3. for construction, test and start-up, and station service for facilities owned or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

C. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser pursuant to the DSI's power sales contract and subject to:

1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and
2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

D. Special Industrial Power

Special Industrial Power is electric power which BPA will make continuously available to any DSI that quali-

fies for the Special Industrial Power rate pursuant to section 7(d)(2) of the Northwest Power Act. This power is similar in nature to Industrial Firm Power, but is subject to greater restriction by BPA. Special Industrial Power is made available to the qualifying DSI upon adoption of, and subject to, an amendment modifying its power sales contract.

E. Auxiliary Power

Auxiliary Power is that power which a DSI requests and which BPA agrees to make available to serve that portion of the DSI's load which is in excess of the DSI's Operating Demand for Industrial Firm Power or Special Industrial Power.

F. Firm Capacity

Firm Capacity is capacity that BPA assures will be available in the amount(s) and during the period(s) specified in the power sales contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

G. Surplus Firm Power

Surplus Firm Power is firm energy, firm energy with capacity, and firm capacity (capacity with energy return requirements) in excess of the amount required to meet BPA's existing contractual obligations to provide firm service. Surplus Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Such power, however, may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

H. Nonfirm Energy

Nonfirm Energy is supplied or made available by BPA to a purchaser under an arrangement that does not have the guaranteed continuous availability feature of firm power. Nonfirm energy is mostly sold under the Nonfirm Energy rate schedule, NF-89. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS-89, which is available as an experimental rate for contract purchase.

In addition, BPA also can make nonfirm energy available under the Nonfirm Energy rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements.

However, Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

I. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. in cases where the purchaser's power sales contract states that the rate for Reserve Power shall be applied;
2. to provide service when no other type of power is deemed applicable; and
3. to serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSPs (section V.E).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. Billing Factors for Demand

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section. Measured Demand shall be that portion of the metered or scheduled demand that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand or the scheduled demand, as hereinafter defined. The Measured Demand shall be determined on either a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

a. Metered Demand

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

(1) at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein. In determining the metered demand, BPA shall exclude any abnormal integrated demands due to or resulting from:

(1) emergencies or breakdowns on, or maintenance of, the Federal system facilities, and

(2) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

b. Scheduled Demand

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) to each system for which scheduled demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Ratchet Demand

The Ratchet Demand in kilowatts shall be the maximum demand established during a specified period of time either during or prior to the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. For utilities purchasing under the PF or NR rate schedules, the Ratchet Demand is based on the highest demand during prior billing months. When the Ratchet Demand is used as a billing factor, BPA shall have specified in the appropriate schedules or GRSPs:

a. the period of time over which the ratchet shall be calculated,

b. the type of demand to be used in the calculation, and

c. the percentage (if any) of that demand which will be used to calculate the Ratchet Demand.

3. Contract Demand

The Contract Demand shall be the maximum number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatthours shall be deemed, for the purpose of these GRSPs, to refer to the term "Contract Energy."

4. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

5. Computed Average Energy Requirement

For computed requirements purchasers, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

6. Operating Demand

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI's power sales contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the demand which the purchaser may impose on BPA; and

b. the total amount of energy during a billing month which the DSI is entitled to purchase from BPA.

7. Curtailed Demand

A Curtailed Demand is the number of kilowatts of industrial power (Industrial Firm Power or Special Industrial Power) during the billing month which results from the DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of industrial power may curtail its demand according to the terms of its power sales contract (which permits up to three levels of Curtailed Demand each month).

8. Restricted Demand

Restricted Demand is the number of kilowatts of industrial power (either Industrial Firm Power or Special Industrial Power) that results when BPA has restricted delivery of such power for one clock-hour or more. BPA shall make such restrictions according to the terms of the DSI's power sales contract. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as there are number of restrictions.

9. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's power sales contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power Rate Schedule at the Standard Industrial Rate. Auxiliary Power sales to DSIs electing to purchase under the Variable Industrial Power Rate Schedule (VI-87) shall be made at the rate determined pursuant to section III of the VI-87 rate schedule. Auxiliary Power sales to DSIs purchasing under the Special Industrial Rate will be made only at the Standard Special Industrial Power Rate.

10. BPA Operating Level

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power (Industrial Firm Power or Special Industrial Power) for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;

b. Curtailed Demand; or

c. Restricted Demand.

The weighted average BPA Operating Level for each DSI can be determined by summing the hourly BPA Operating Levels and dividing by the number of hours in the billing month.

Each DSI must request service from BPA for each billing month in accordance with the terms of the power sales contract. The requested level of service will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request and BPA may agree to a level of service for the Offpeak Periods other than that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an unauthorized increase.

Any DSI whose Measured Demand, before adjustment for power factor, during any 1 hour exceeds the BPA Operating Level for that hour shall be subject to unauthorized increase charges for each kilowatt-hour of unauthorized increase associated with each overrun.

Only the BPA Operating Level applicable during the Peak Period will be used in determining the Billing Demand for power purchased under the Industrial Firm Power rate schedule, the Variable Industrial Power rate schedule, and the Standard Rate under the Special Industrial rate schedule. During the Peak Period the BPA Operating Level may be no greater than the Operating Demand for the billing month unless the customer has requested, and BPA has agreed to supply, the Auxiliary Demand.

B. Billing Factors for Energy

1. Measured Energy

Measured Energy shall be that portion of the metered or scheduled energy that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy or the scheduled energy, as hereinafter defined.

a. Metered Energy

The metered energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the power sales contract, and delivered to a purchaser:

(1) at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein.

b. Scheduled Energy

The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) for each system for which scheduled energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Contract Energy

The Contract Energy shall be the maximum number of kilowatthours that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract.

C. Billing Adjustments

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters that are ratcheted to prevent reverse registration. These data then shall be adjusted for losses, if applicable, before determination of the average power factor.

When deliveries to a purchaser at any point of delivery either:

a. include more than one class of power, or

b. are provided under more than one rate schedule and it is impracticable to meter the kilowatthours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a low power factor. Such restriction may be made to a point of delivery or to a purchaser's system at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 75 percent.

2. Outage Credit

To the extent that BPA is unable to provide full service to a purchaser during the billing month as a result of interruptions in service due to reasons cited in the General Contract Provisions, BPA shall adjust the charges for those hours for billing demand for such purchaser to reflect BPA's inability to provide full service, provided such adjustment is mandated by the purchaser's power sales contract. The adjustment is provided on a point of delivery basis. To compute the adjustment for noncoincidentally billed systems, BPA shall determine the monthly demand charge(s) for the point(s) of delivery where the outage(s) occurred, multiply by the number of hours of outage, and divide by the total number of hours in the billing month. For coincidentally billed points of delivery, the adjustment shall apply only to those points of delivery at which BPA was unable to provide full service. For partial outages (such as an outage on one feeder in a substation with several feeders), BPA shall determine an equivalent interruption in order to arrive at the number of hours to be used in the calculation of the credit.

3. Low Density Discount (LDD)

a. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power purchased under the Priority Firm Power rate schedule by eligible purchasers as defined in section b, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year. Retroactive billing for the LDD may be required if the data are

not available by the January billing date. The level of the discount shall be determined from the following ratios:

(1) the purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses, but excluding nonfirm sales to nonfirm retail loads, such as boiler loads served under BPA's alternate fuel policy) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

(2) the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the number of pole miles of distribution line at the end of such year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on data provided in the purchaser's annual financial and operating report. In calculating these ratios, BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see a.(1) and a.(2) above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. Low Density Discounts issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

b. Eligibility Criteria

To qualify for a discount, the purchaser must meet all six of the following eligibility criteria:

(1) the purchaser must serve as an electric utility offering power for resale;

(2) the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the region served by BPA;

(3) the purchaser's average retail rate for the reporting year must exceed the average Priority Firm Power rate in effect for the qualifying period by 10 percent. For CY 1989, the average Priority Firm Power rate shall be the average of the PF-87 rate for 9 months and the PF-89 Preference rate for 3 months. For CY 1990, the average Priority Firm Power rate shall be the PF-89 Preference rate.

(4) the purchaser's kilowatthour-to-investment ratio (Ratio 3.a.(1)) must be less than 100;

(5) the purchaser's consumers-per-mile ratio (Ratio 3.a.(2)) must be less than 12; and

(6) the purchaser must qualify for a discount based on the criteria in section c, below.

c. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for those discounts are listed below.

(1) Three percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 25 but less than 35; or

(b) the consumers-per-mile ratio is equal to or greater than 5 but less than 7.

(2) Five percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 15 but less than 25; or

(b) the consumers-per-mile ratio is equal to or greater than 3 but less than 5.

(3) Seven percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is less than 15; or

(b) the consumers-per-mile ratio is less than 3.

4. Irrigation Discount

a. Basic Irrigation Discount Principles

A discount of 4.6 mills per kilowatthour shall be applied to the charges for qualifying irrigation energy purchased under the Priority Firm Power and New Resource Firm Power rate schedules, during the billing months of April through October. This discount shall be applied subsequent to calculation of the Low Density Discount, if applicable. Any energy on which the irrigation discount is claimed shall be metered separately by the Purchaser, and used exclusively for agricultural irrigation or drainage pumping.

b. Qualifying Energy Purchases

The qualifying irrigation energy shall be determined as follows:

(1) All irrigation energy must be used exclusively for the purpose of irrigation and drainage pumping on agricultural land and be measured at the end-use irrigation customer's meter. The discount shall apply to the measured energy sales at the end-use.

(2) Energy subject to the discount must be purchased during the billing months of April through October.

(3) Purchasers of exchange energy under the Residential Purchase and Sale Agreement (RPSA) are eligible for the irrigation discount for the portion of their irrigation sales qualifying for the exchange under the RPSA contracts.

(4) General requirements customers are eligible for an irrigation discount for a portion of their irrigation sales equal to the share of their total sales served by BPA firm purchases (i.e., total irrigation and drainage pumping sales multiplied by BPA billing energy for Priority Firm or New Resources firm purchases divided by the total firm utility system requirements for the billing month).

c. Initial Reporting Requirements

Requests for the Irrigation Discount must include the following information:

(1) To receive an irrigation discount, a purchaser must file a request for the discount with its local BPA Area or District office by April 1 each year.

(2) In the request, the purchaser must certify that the irrigation energy is sold exclusively for use in irrigation and drainage pumping on agricultural land and that the discount is passed, in its entirety, to the irrigation consumer, regardless of whether the utility has raised its rates. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.

d. Annual Reporting Requirements

Purchasers shall submit an annual irrigation report to their local BPA Area or District office in order to receive the irrigation discount. Purchasers are required to report information related to monthly irrigation energy sales. If a utility does not read its irrigation meters monthly, the utility must estimate its monthly irrigation sales. These estimates shall be reviewed by BPA area and/or district offices. Purchasers must read their meters within 3 working days of the beginning and ending of the irrigation discount period (April-October). In order to qualify for the discount, the purchaser must submit all data to BPA by December 31 of the calendar year in which the sales occurred. Irrigation reports to BPA shall include the following monthly information for the reporting period:

(1) utility name and period for which the report is being made;

(2) total irrigation sales and total qualifying irrigation energy sales (in kilowatthours) by month;

(3) total qualifying irrigation sales (in kilowatthours) by month under 400 horsepower, for exchanging utilities;

(4) total utility firm system requirements for other than full requirement customers by month (in kilowatthours);

(5) total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatthours ; and

(6) the Purchaser shall list each irrigation and drainage account number in its annual report and whether each irrigation consumer is billed monthly, bimonthly, or seasonally. If the Purchaser is an exchanging utility, the Purchaser shall also identify the size (in horsepower) of the connected load for each active account. A utility may submit monthly reports, if it chooses. In that case, the active list of accounts should be included in the last monthly report submitted.

5. Cost Recovery Adjustment Clause

a. Applicable Rate Schedules

The Cost Recovery Adjustment Clause (CRAC) ap-

plies to the Priority Firm Power (Exchange and Preference) (PF-89), Industrial Firm Power (IP-89), Variable Industrial Power (VI-87), Firm Capacity (CF-89), and New Resource Firm Power (NR-89) rate schedules. A percentage adjustment, labeled as CRAC%, is calculated for specific periods and applied to these rates by various formulas.

b. Evaluation and Adjustment Periods

There are two evaluation and adjustment periods for the Cost Recovery Adjustment Clause.

(1) Period 1

Period 1 is comprised of an evaluation period covering FY 1989 (October 1, 1988, through September 30, 1989) and an adjustment period of January 1, 1990, through September 30, 1990.

After September 30, 1989, BPA shall evaluate its preliminary, unaudited financial position by measuring its FY 1989 net revenues (BPA's total FY 1989 revenues less FY 1989 expenses).

Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

If the net revenues are less than zero for the evaluation period (FY 1989) as specified herein, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1990, and ending September 30, 1990.

(2) Period 2

Period 2 is comprised of an evaluation period covering FY 1990 and an adjustment period of January 1, 1991, through September 30, 1991.

Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

After September 30, 1990, BPA shall evaluate its preliminary, unaudited financial position by measuring its FY 1990 net revenues (BPA's total FY 1990 revenues less FY 1990 expenses). The amount of any CRAC adjustment resulting from Period 1 evaluation shall be subtracted from FY 1990 revenues to obtain the adjusted FY 1990 revenues. The adjusted FY 1990 revenues less FY 1990 expenses equals the adjusted FY 1990 net revenues. If adjusted FY 1990 net revenues are less than zero for Period 2, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1991, and ending September 30, 1991.

c. Formulas for the Cost Recovery Adjustment Clause

(1) Adjustment Calculation

BPA shall determine the net revenue for each evaluation period using the following formulas:

(a) Period 1:

NR1 = revenues - expenses

where:

revenues = total operating revenues (in milions of dollars) from the FCRPS Statements of Revenues and Expenses;

expenses = sum of total operating expenses, net interest expense, and any litigation settlement expenses or other extraordinary expenses shown separately on the FCRPS Statements of Revenues and Expenses (in millions of dollars);

NR1 = FY 1989 net revenues (in millions of dollars).

If NR1 is zero or greater, then there will be no rate adjustment; and

CR1 = zero

If NR1 is less than zero:

CR1 = absolute value of NR1, for Period 1.

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1990, through September 30, 1990:

(i) If CR1 is greater than $29.7 million, then the CRAC% equals the lesser of:

(A) (CR1+12.015)/13.899; or

(B) 10.0 percent.

(ii) If CR1 is less than or equal to $29.7 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

CRAC% = CR1/9.902

(b) Period 2:

NR2 = (revenues-ACR1) - expenses

where:

NR2 = Adjusted FY 1990 net revenues (in millions of dollars); and

ACR1 = The lesser of CR1 or $127.0 million; or equals zero if rates were not adjusted, at the discretion of the Administrator, in Period 1.

If NR2 is zero or greater, then there will be no rate adjustment.

If NR2 is less than zero, then:

CR2 = absolute value of NR2 for Period 2.

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1991, through September 30, 1991:

(i) If CR2 is greater than $33.1 million, then the CRAC% equals the lesser of:

(A) (CR2+12.083)/15.056; or

(B) 10.0 percent.

(ii) If CR2 is less than or equal to $33.1 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

CRAC% = CR2/11.014

d. Application to Irrigation Discount

In addition to the direct application of the cost recovery adjustment percentage (CRAC%) to the irrigation discount, an additional adjustment shall be made so that irrigation loads are not disproportionately affected by a 9-month adjustment period as compared to a 12-month adjustment period. The direct and additional adjustments are reflected in the following formula:

Adjusted Irrigation Discount (in mills per kilowatthour)

$$= 4.6 * \left(1 + \frac{CRAC\%}{100}\right) + (0.046 * CRAC\%)$$

where:

4.6 = Irrigation discount applicable to PF-89 and NR-89, in mills per kilowatthour; and

0.046 = adjustment to account for the disproportionate impact of CRAC on irrigation loads, in mills per kilowatthour per percentage CRAC adjustment.

e. Cost Recovery Adjustment Clause Implementation Process

(1) Within 30 days after the end of FY 1989 and within 30 days after the end of FY 1990, BPA shall make an initial calculation to identify the preliminary, unaudited net revenues.

(2) On or about November 1 of each of the years 1989 and 1990, BPA shall notify interested persons and the purchasers under each applicable rate schedule of BPA's initial findings concerning the net revenues for the evaluation period.

(a) If no adjustment is required, or if the Administrator waives implementation of an adjustment, BPA shall state in the notice the basis for its decision, and no further process will be required.

(b) If BPA determines that an adjustment to applicable rates is required, BPA shall state in the notice the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA. Such documentation, if nonproprietary and/or nonprivileged, shall be available upon request unless unduly burdensome. The notice shall also contain the tentative schedule for the remainder of the implementation process.

(3) On or about November 6, 1989, and November 5, 1990, BPA shall conduct a public meeting in which interested persons and purchasers under each applicable rate schedule may seek off-the-record clarification, calculation, and application of the adjustment amount to spe-

cific rate schedules. For the purpose of further mailings, a list of the names and addresses of interested persons and purchasers (hereafter referred to as "mailing list") shall be compiled at this meeting.

(4) On or about November 10, 1989, and November 9, 1990, purchasers under each applicable rate schedule may submit information requests to BPA regarding the adjustment. The requests shall also be mailed to all persons on the mailing list. BPA shall respond to the requests within 2 working days of their receipt, or as soon as practicable if 2 days is insufficient time within which to respond.

(5) On or about November 17, 1989, and November 16, 1990, interested persons and purchasers under each applicable rate schedule may submit written comments to BPA regarding the adjustment. The comments shall also be mailed to all persons on the mailing list.

(6) On or about December 1, 1989, and November 30, 1990, commenters may respond to any comments.

(7) On or about December 1, 1989, and November 30, 1990, BPA may release, if available, revised preliminary unaudited net revenues and any resulting revised adjustment to applicable rate schedules.

(8) On or about December 15, 1989, and December 14, 1990, BPA shall conduct an on-the-record public comment forum in which interested persons and purchasers under each applicable rate schedule may present oral comments to BPA.

(9) On or about December 20, 1989, and December 19, 1990, BPA shall notify interested persons and purchasers under each applicable rate schedule of the audited net revenue balance, the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA.

(10) If there is a rate adjustment due the CRAC following the FY 1989 evaluation period, it shall be in effect from January 1, 1990, through September 30, 1990.

If there is a rate adjustment due to the CRAC following the FY 1990 evaluation period, it shall be in effect from January 1, 1991, through September 30, 1991.

6. Coincidental Billing

Purchasers of Priority Firm Power and New Resource Firm Power shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule(s) unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purpose of these rate schedules and GRSPs, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery. See the Special Provisions Exhibits of the Power Sales Contract, GCP, E, 17.

7. Conservation Surcharge

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for all power purchased under each rate schedule subject to the surcharge. The PF, CF, and NR rate schedules are subject to the Conservation Surcharge. If only a portion of the customer's service area is subject to the surcharge, then the amount of the surcharge shall equal 10 percent of the total charge for all power purchases multiplied by: (a) the portion of the customer's total retail load that is subject to the surcharge, divided by (b) the customer's total retail load.

D. Billing-Related Definitions

1. Peak Period

The Peak Period includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive. There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday. Any charges based on Peak Period hours shall be computed starting with the 8 a.m. meter reading since this reading applies to the 7 o'clock hour (7 a.m. to 8 a.m.). The 10 p.m. meter reading (for the 9 p.m. to 10 p.m. period) is the last meter reading of the day applicable to the Peak Period.

2. Offpeak Period

The Offpeak Period includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 7 a.m., Monday through Saturday and all hours on Sunday. This definition does not apply to the Special Industrial Offpeak Rate.

SECTION IV. OTHER DEFINITIONS

A. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if it is so designated pursuant to the provisions of its power sales contract.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract.

B. Definitions Relating to Nonfirm Energy Decremental Cost

Unless otherwise specified in a contractual arrangement, decremental cost as applied to Nonfirm Energy transactions shall be defined as:

1. All identifiable costs (expressed in mills per kilowatthour) associated with the use of a displaceable thermal resource or end-user load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

2. All identifiable costs (expressed in mills per kilowatthour) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the purchaser.

C. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for nonfirm energy, including any applicable service charges or rate adjustment, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning October 1, 1987.

2. Monthly Notification of the NF Rate Cap

Prior to the beginning of a calendar month BPA shall perform the calculations contained in section IV.C.3. of these GRSPs to determine the effective NF Rate Cap for that calendar month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. BPA may waive this requirement only if BPA does not intend to offer Nonfirm Energy at prices above BASC at any time during a month. The notification will be given at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap applies. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the period the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC + .30(DEC - BASC)

Where:

BASC = BPA's average system cost, determined by dividing BPA's total system costs by BPA's total system sales. For this rate period BASC has been determined to be 23.2 mills per kilowatthour.

DEC = The Decremental Fuel Cost as determined in accordance with section IV.C.5. of these GRSPs.

4. Determination of BPA's Average System Cost

For purposes of determining BPA's Average System Cost (BASC), the following definition shall apply:

a. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent

general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

5. Determination of Decremental Fuel Cost

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap, a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. The monthly decremental fuel cost shall be:

a. the sum of:

(1) the average California price for gas determined by multiplying the monthly gas use (WGU)developed pursuant to section IV.C.8.a. times the monthly California gas price (MGP) determined pursuant to section IV.C.6 rounded to the nearest tenth of a mill; and

(2) the average California price for petroleum determined by multiplying the monthly petroleum use (WOU) developed pursuant to section IV.C.8.b times the monthly California petroleum price (MOP) determined pursuant to section IV.C.7. rounded to the nearest tenth of a mill.

b. divided by the sum of the monthly gas use (WGU) and monthly petroleum use (WOU) developed in section IV.C.8.a. and b. respectively rounded to the nearest tenth of a mill.

6. California Gas Price

The monthly gas price (MGP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MGP = \frac{AGP * HGP}{10}$$

Where:

AGP = the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HGP = the historical relationship between gas prices in the effective month of the NF Rate Cap (month t) and the month in which the gas prices are reported in EPM (month r) using the following procedures:

a. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California gas price in a. above, by the average monthly California gas price in b. above, and rounding to the nearest one-tenth, or three significant places.

10 = the factor for converting gas prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.

7. California Petroleum Price

The monthly petroleum price (MOP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MOP = \frac{AOP * HOP}{10}$$

Where:

AOP = the last available average oil price for California electric utility plants expressed in cents per million Btu reported in *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HOP = the historical relationship between petroleum prices in the effective month of the NF Rate Cap (month t) and the last month in which the petroleum prices are reported in EPM (month r) using the following procedures:

a. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly

petroleum prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California petroleum price in a. above, by the average monthly California petroleum price in b. above, and rounding to the nearest one-tenth of a percent, or three significant places.

10 = the factor for converting petroleum prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.

8. Weighting Factors

For purposes of determining California fuel prices for the month, gas and petroleum prices will be weighted based on California's historical use of these two alternative fuels.

a. Historical Gas Use in California

The following formula shall be used to determine the weighting factor for gas prices (WGU):

WGU = CGU * HGU

Where:

CGU = the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HGU = the historical relationship between gas consumptions in the effective month of the NF Rate Cap (month t) and the month for which gas consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-gas fired generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of gas in California for the month t as determined in (1) above by the average consumption of gas for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

b. Historical Petroleum Use in California

The following formula shall be used to determine the weighting factor for petroleum prices (WOU):

WOU = COU * HOU

Where:

COU = the monthly net petroleum-fired generation, expressed in gigawatthours, in California in the most recent monthly issue of *Electric Power Monthly* (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HOU = the historical relationship between petroleum consumptions in the effective month of the NF Rate Cap (month t) and the month for which petroleum consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be di-

vided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of petroleum in California for the month t as determined in (1) above by the average consumption of petroleum for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

D. Determination of BPA's Average System Cost.

For purposes of determining BPA's Average System Cost (BASC), the following definition shall apply:

1. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

2. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted in each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm or New Resource Firm Power shall pay in accordance with the Nonfirm Energy rate schedule, NF-89, and Emergency Capacity rate schedule, CE-89, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or

2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefore settled under exchange agreements.

B. Construction, Test and Start-Up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.

2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on line and to ensure that the project is working properly.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates During Initial Operation Period—Transitional Service

1. Eligibility for Transitional Service

For an initial operating period, as specified in the power sales contract, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

a. DSIs having new, additional or reactivated plant facilities, and

b. utility purchasers serving industrial purchasers with power purchased from BPA. BPA will provide transitional service to utilities for only those industrial loads for which the demand can be separately metered by the utility and recorded on a daily basis.

2. Calculation of the Daily Demand

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the Daily Demands as adjusted for power factor.

Demand for each day shall be defined as 100 percent of the Measured Demand for the day (regardless of whether such Measured Demand occurs during the Peak Period or the Offpeak Period).

3. Billing for Transitional Service

Utilities receiving transitional service shall provide BPA with Daily Demand information for the industrial consumer for whom transitional service is provided. To compute the power bill for the point of delivery which includes the load being served with transitional service, BPA shall, at its discretion, either:

a. determine the demand for the pertinent point of delivery without the industrial load and then add the average daily demand for such industrial load; or

b. bill the entire point of delivery on a daily demand basis.

Daily demand billing shall not affect the level of any curtailment charge or energy charge assessed by BPA.

D. Changes in a DSI's BPA Operating Level

If a DSI requests a waiver regarding the notice requirements specified in the DSI's power sales contract for a voluntary change in its BPA Operating Level, and if BPA does not grant the waiver, or if the DSI fails to give notice of such a change and does not request a waiver, the DSI shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

E. Restriction of Deliveries

Deliveries of capacity or energy to any purchaser may be restricted when operation of the facilities used by BPA to serve such purchaser is:

1. suspended,
2. interrupted,
3. interfered with,
4. curtailed, or
5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

SECTION VI. BILLING INFORMATION

A. Determination of Estimated Billing Data

If the amounts of capacity, energy, or the 60-minute integrated demands for energy purchased from BPA must be estimated from data other than metered or scheduled quantities, historical patterns, and pertinent weather data, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, derived by any method, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

B. Load Shift and Outage Reports

Load shift and outage reports must be submitted to BPA within 4 days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. If customer reports are not received in a timely manner, BPA has the option to withhold load shift or outage credit.

C. Billing for New Large Single Loads

Any BPA customer whose total load includes one or more New Large Single Loads (NLSL) shall be billed for the NLSL(s) at the New Resource Firm Power Rate. The power requirements associated with the NLSL shall be established in a manner consistent with the provisions of this section.

The purchaser shall warrant to BPA that NLSLs are separately metered. The metering must include provisions for determining:

1. the NLSL demand during BPA's diurnal capacity billing periods,
2. the NLSL energy during BPA's energy billing periods, and
3. the NLSL reactive energy for the billing month.

The design for the metering equipment for the NLSL must be approved by BPA. Testing and inspections of such metering installations shall be as provided in the General Contract Provisions.

On a monthly basis, each purchaser of New Resource Firm Power shall report to BPA the quantity of power used by the NLSL during the purchaser's billing period. Data provided to BPA by the purchaser must be submitted to BPA within 2 normal working days of the date the purchaser reads the meters. BPA may elect to adjust the NLSL data for losses from the point of metering to the closest BPA point of delivery for the purchaser.

D. Determination of Measured Demand

1. For points of delivery with fully operational metering under the Revenue Metering System (RMS), demand shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.
2. For points of delivery that do not have RMS metering, demand shall be measured from 0000 hours on the first complete (24 hour) day of the available metering data through 2400 hours on the last complete day of the available metering data. Billing demand will be determined from the period of available metering data that most closely matches the official billing period of the customer.

E. Determination of Measured Energy

1. For points of delivery with fully operational metering under RMS, energy shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.
2. For points of delivery that do not have RMS metering, measured energy shall be the quantity of usage recorded on the meter between meter readings.

F. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less than or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately.

The calendar month in which the purchaser's meter is scheduled to be read determines the billing month. (Thus, a bill associated with a meter scheduled to be read on April 10 would be an April bill.) The charges for the winter and summer periods identified in the rate schedules apply to the purchaser's billing months.

G. Payment of Bills

Bills for power shall be rendered monthly by BPA. Failure to receive a bill shall not release the purchaser from liability for payment. Bills for amounts due BPA of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). This requirement holds also for revised bills (see section 6 below). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the purchaser), the due date shall be the next following business day.

4. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto under such contract.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

As necessary, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than the

amount of the bill which it is replacing, the additional amount will be billed on a separate bill, and the date of the revised bill shall be its date of issue.

SECTION VII. VARIABLE INDUSTRIAL RATE PARAMETERS AND ADJUSTMENTS

A. Monthly Average Aluminum Price Determination

1. Calculation of the Monthly Billing Aluminum Price

The monthly billing aluminum price shall be determined by BPA for each billing month. For purposes of this rate schedule, the monthly billing aluminum price shall be based on the average price of aluminum in U.S. markets during the third calendar month prior to the billing month. The average price of aluminum in U.S. markets shall be defined as the average U.S. Transaction Price reported for the month by *Metals Week,* in cents per pound, rounded to the nearest tenth of a cent.

2. Notification of the Monthly Average Aluminum Price

BPA shall provide, 45 days prior to the billing month, written notification to purchasers under this rate schedule of the monthly billing aluminum price to be used for billing purposes. Upon written request *supporting documentation shall be provided.*

3. Changes in Aluminum Price Indicators

In the event that BPA determines that factors outside its control render the monthly average U.S. Transaction Price unusable as an approximation of U.S. market prices, BPA may develop and substitute another indicator for prices in U.S. markets. BPA shall notify interested parties of its intent to do so at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason for the substitution and specify the replacement indicator it intends to use. BPA also shall describe the methodology to determine the monthly billing aluminum price to be used for billing purposes under this rate schedule and shall provide the necessary data to be used in the calculation. Interested persons will have until close of business 3 weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final methodology and the substitute aluminum price index to differ from those proposed. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month the new indicator shall be effective.

B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices

On July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices, as stated in section III.B of the rate schedule, shall be subject to change for billing purposes as herein described. The term "annual adjustment date" shall refer to July 1 of each year.

1. Implementation Procedures

Beginning in 1987 and every year thereafter, prior to April 1 of that year, BPA shall provide the purchasers under this rate schedule preliminary written estimates of proposed adjustments to the Lower and Upper Pivot Aluminum Prices. By the last working day of the month of April, BPA shall notify interested parties in writing of BPA's revised determinations concerning changes to the Lower and Upper Pivot Aluminum Prices. BPA shall describe how the adjustments were determined and provide the data used in the calculations. In addition to written notification, BPA may, but is not obligated to, hold a public comment forum to clarify its determinations and solicit comments. Interested persons may submit comments on the determinations to BPA and other parties. Comments will be accepted until close of business on the last working Friday in May. Consideration of comments and more current information may result in the final adjustment differing from the proposed adjustment. By June 30 of each year, BPA shall notify all VI purchasers, *those parties that submitted comments, and* parties that requested notification, of the final determination.

2. Annual Adjustment Procedures

a. Annual Adjustment of the Lower Pivot Aluminum Price

Beginning with the July 1, 1987, annual adjustment date, for each year that the Variable Industrial rate is in effect, the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Lower Pivot Aluminum Price shall be revised by multiplying 59 cents per pound by the Cost Escalation Index described in section VII.B.3.b of these GRSPs and rounded to the nearest tenth of a cent. The revised Lower Pivot Aluminum Price shall replace the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

b. Annual Adjustment of the Upper Pivot Aluminum Price

For each year that the Variable Industrial rate is in effect, the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule shall be adjusted on the July 1 annual adjustment date.

(1) Annual adjustment for the period beginning July 1, 1987, and ending June 30, 1991

The Upper Pivot Aluminum Price shall be revised by multiplying 72 cents per pound by the Cost Escalation Index described in section VII.B.3.c of these GRSPs and rounded to the nearest tenth of a cent. The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

(2) Annual Adjustment for the period beginning July 1, 1991, and ending June 30, 1993

The Upper Pivot Aluminum Price will be adjusted such that the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs is the midpoint between the adjusted Upper Pivot Aluminum Price and the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 below, except as limited to the greater of 65 cents per pound or the adjusted Lower Pivot Point for the year.

The Upper Pivot Aluminum Price shall equal the greater of:

(a) (2)(AAP) - ALP:

where

AAP = the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs.

ALP = the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 of these GRSPs.

(b) 65.0 cents per pound escalated to current dollars using the Cost Escalator for the Upper Pivot Aluminum Price described in section VII.B.3.c of these GRSPs.

or

(c) The adjusted Lower Pivot Aluminum Price for the year.

The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 months.

3. Cost Escalators

a. The cost indices described below shall be used in calculating the appropriate cost escalators. Each index shall be rounded to the nearest one-tenth of a percent, or three significant places.

(1) Electricity Cost Index

The average VI-87 rate in mills per kilowatthour based on the Plateau Energy Charge and the Discount for Quality of First Quartile Service in effect on the April 1 preceding the annual adjustment date and a load factor of 98.5 percent; divided by 22.8 mills per kilowatthour (the average VI-86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) Labor Cost Index

The annual average hourly earnings for the U.S. primary aluminum industry (SIC 3334) over the previous complete calendar year, from the Employment and Earnings, published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS), divided by $14.20 per hour (the value of SIC 3334 earnings reported for 1985).

(3) Alumina Cost Index

The annual average of the monthly billing aluminum prices described in section VII.A of the GRSPs for the previous 1-year period beginning July 1 through June 30 divided by 50.8 cents per pound (the average U.S. Transaction price over the period April 1985 through March 1986).

(4) Other Costs Index

The annual average GNP Implicit Price Deflator for the previous complete calendar year, as published by the U.S. Department of Commerce, Bureau of Economic Analysis, divided by 1.115 (the value of the GNP Implicit Price Deflator for 1985 with 1982 = 1.000).

In the event the indices delineated above are discontinued or revised in a manner that BPA determines renders them unusable for calculating a consistent cost index, BPA will adjust or substitute another similar price index, following advance notification and opportunity for public comment as described in section VII.B.1 of these GRSPs.

b. The Cost Escalator for the Lower Pivot Aluminum Price shall be a weighted average of the four indices contained in section VII.B.3.a above. The following weights shall be assigned each index:

Electricity Cost Index	.30
Labor Cost Index	.20
Alumina Cost Index	.20
Other Costs Index	.30

c. The Cost Escalator for the Upper Pivot Aluminum Price shall be a weighted average of the Electricity Cost and Other Cost Escalators as stated in sections VII.B.3.a.(1) and VII.B.3.a.(4) above. The following weights shall be assigned each index:

Electricity Cost Index	.25
Other Costs Index	.75

4. Average Historical Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, an average historical aluminum price shall be calculated for the period the Variable rate has been in effect. The average historical aluminum price shall be determined following the procedures set forth below:

a. Each monthly billing aluminum price determined pursuant to section VII.A of these GRSPs for the period August 1, 1986, through June 30 immediately preceding the annual adjustment date, shall be escalated to the current year dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly billing aluminum prices shall be divided by the number of months in the period and rounded to the nearest tenth of a cent to obtain the Average Historical Aluminum Price.

5. Average Historical Lower Pivot Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, the average of the Lower Pivot Aluminum Prices for the period the Variable Industrial rate has been in effect shall be calculated following the procedures set forth below:

a. The Lower Pivot Aluminum Price in each month for the period August 1, 1986, through June 30 of the calendar year preceding the annual adjustment date, shall be escalated to the current year's dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly Lower Pivot Aluminum Prices shall be divided by the number of months in the period, and rounded to the nearest tenth of a cent to obtain an Average Historical Lower Pivot Aluminum Price.

6. Price Deflator Procedures

For purposes of converting nominal dollars to real dollars in the calculation of the Average Historical Aluminum Price and the Average Historical Lower Pivot Aluminum Price, the following Price Deflator procedures shall be used:

a. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months July through December shall be inflated by multiplying the price by the ratio of the GNP Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year in which the price occurred.

b. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months January through June shall be inflated by multiplying the price by the ratio of the Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year prior to the year in which the price occurred.

Each price shall be rounded to the nearest tenth of a cent.

11-3-83

GCP Form PSC (SW) - 1

GENERAL CONTRACT PROVISIONS

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IN REFERENCE TO MEANING

1. Definitions. The definitions in the body of this contract and the following additional definitions apply to this exhibit.

(a) "Contractor" means the Purchaser.

(b) "Energy Requirements of Any Pacific Northwest Customer" means the full requirements for electric energy of (1) any purchaser from Bonneville for direct consumption in the Pacific Northwest, and (2) any Non-Federal Utility in that region in excess of (A) the hydroelectric energy available for its own use from its generating plants in the Pacific Northwest; (B) any amount of energy included in the resources of such utility which (i) is included in the firm resource exhibit of any Bonneville customer's power sales contract, (ii) was disposed of by such utility outside the Pacific Northwest, (iii) increases the firm energy requirements of such utility or any other Bonneville customer as a result of such disposition, and (iv) could have been conserved or otherwise retained for service to loads in the Pacific Northwest, in Bonneville's determination, through reasonable measures taken by such utility; and (C) any additional energy available for use in the Pacific Northwest which, under a then existing contract, the utility (i) can obtain at no higher incremental cost than the rate charged by the Bonneville, or (ii) is required to accept.

(c) "Excess Energy" means electric energy which the Purchaser determines in its sole discretion that it has available for sale to Bonneville in excess of its other obligations.

(d) "Extra-High Voltage Transmission Lines" means the transmission lines and related terminal facilities described in the Intertie Report of the Secretary of the Interior dated June 1964, as amended and supplemented.

(e) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(f) "Federal Energy Regulatory Commission" means the Federal Energy Regulator Commission or its successor.

(g) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatthours delivered at any point during any clock hour.

(h) "Non-Federal Utility" means any utility not owned or controlled by the United States, including any entity (1) which such a utility owns or controls, in whole or in part, or is controlled by; (2) which is controlled by those controlling such utility; or (3) of which such utility is a member.

(i) "Pacific Northwest" means the same as such term is defined in P.L. 96-501.

(j) "Peaking Energy" means the electric energy accompanying the delivery of Surplus Peaking Capacity.

(k) "Peaking Replacement Energy" means that portion of the Peaking Energy which is not Surplus Energy and which Bonneville requires the Purchaser to replace.

(l) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(m) "Provisional Energy" means electric energy generated on the Federal System which can be conserved, for which there is no immediate demand in the Pacific Northwest at any established rate, but for which Bonneville determines there may be a demand in meeting the future energy requirements of the Pacific Northwest.

(n) "Provisional Replacement Energy" means energy which the Purchaser is obligated to make available to Bonneville by reason of receipt of Provisional Energy.

(o) "Surplus Energy" means electric energy generated at Federal hydroelectric plants, excluding the Canyon Ferry Project, in the Pacific Northwest or generated on the Federal System which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate or for which there is no market in the Pacific Northwest at any rate established for the disposition of such energy.

(p) "Surplus Peaking Capacity" means electric peaking capacity at Federal hydroelectric plants, excluding the Canyon Ferry Project, in the Pacific Northwest or electric peaking capacity on the Federal System for which there

is no demand in the Pacific Northwest at any established rate or for which there is no demand in the Pacific Northwest at the rate established for the disposition of such capacity.

(q) "Treaty" means the Treaty between the United States and Canada relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington January 17, 1961.

(r) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Purchaser's works, system, or other physical facilities; the Federal System Facilities or the physical facilities owned, controled or used by any non-Federal Utility in the Pacific Northwest resulting in such utility's inability to meet its requirements; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Non-Federal Utility to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Purchaser or Bonneville or any Non-Federal Utility by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Non-Federal Utility, causing failure, damage, destruction or reduction of transmission capacity of any works, system or facilities of such party or Non-Federal Utility; the word "failure" shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Non-Federal Utility, and which are issued in any bona fide proceeding by:

(i) any duly constituted court of general jurisdiction; or

(ii) any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Non-Federal Utility has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jurisdiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Non-Federal Utility in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Non-Federal Utility, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

The provisions of this definition relating to Non-Federal Utilities in the Pacific Northwest shall be applicable only to the delivery of Surplus Energy.

2. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained in this exhibit, the former shall prevail.

(b) If a provision in the General Rate Schedule Provisions incorporated in the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit is in conflict with a provision contained in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party hereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions of this contract which it would otherwise have.

IN REFERENCE TO COMPUTATION OF CHARGES

3. Measurements. Each measurement of each meter mentioned in this contract shall be the measurement automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any

such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

4. Adjustment for Change of Conditions. Changes in conditions may occur after the date of execution of this contract which substantially affect factors required by this contract to be used in determining (a) the charge for a service or for use of facilities provided by Bonneville other than charges for the sale of electric power and energy; or (b) the amount of losses from the transmission or transformation of electric power or energy. Such factors will then be changed in an equitable manner which will conform to such changes in conditions.

5. Adjustment for Inaccurate Metering. If any meter mentioned in this contract fails to register, if the measurement made by such meter during a test made as provided in section 18 hereof varies by more than one percent from the measurement made by the standard meter used in such test or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such inaccurate measurements were made, if such period can be determined. If such period cannot be determined the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter; or (b) 6 months. Such corrected measurements shall be used to recompute the amounts due from the Purchaser for the electric power and energy made available under this contract during such period and shall be used, when applicable, in future billings to the Purchaser. If the total amount due from the Purchaser for such period as recomputed varies from the total amount previously billed by Bonneville, Bonneville shall adjust the wholesale power bill(s) as soon as practicable.

IN REFERENCE TO RATES

6. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the sale and disposition of electric power, capacity or energy sold pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" mean any date as specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Purchaser 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Purchaser; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Purchaser shall pay Bonneville for the electric power and energy made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this

contract, and in accordance with the terms thereof, and of the General Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville rates. Rates shall be applied in accordance with the terms thereof, the General Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

7. Retail Rates.

(a) Copies of the Purchaser's schedules of retail rates, including special contract rates, if any, in effect when this contract is executed, and those hereafter adopted, endorsed with the effective date thereof, shall be furnished to Bonneville, and Bonneville shall keep said rates on file. The Purchaser agrees to serve each of its consumers at, and in accordance with, the rates, charges, and provisions set forth in the applicable rate schedules on file where and as required by law or on file in Bonneville's office. Notice of the intent to change retail rates shall be given to Bonneville either 45 days prior to their effective date or as soon as the regulatory process allows or shall be mailed to Bonneville on the same day as a notice of a rate change given to a state regulatory authority by the Purchaser, whichever will result in the later receipt of such notice by Bonneville.

(b) The retail rates and charges shall be reasonable and nondiscriminatory, consistent with the principles of the Bonneville Project Act, subject to the right of the Purchaser to adopt retail rates designed to achieve cost-effective conservation or renewable resources; provided, however, that rates and charges which have been approved in accordance with the procedures of a state regulatory agency having jurisdiction shall be deemed

prima facie reasonable and nondiscriminatory. The Purchaser shall maintain records containing the data, analyses, and other factors which are used to develop and form the basis for its proposed or final retail rates. At Bonneville's request, such records as are available for public inspection shall be supplied during the rate development process or after the rates have been adopted.

IN REFERENCE TO DELIVERY OF POWER

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power or energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Purchaser at the Point(s) of Delivery and at such voltage(s) as specified. Unless otherwise agreed, delivery at more than one voltage shall constitute delivery at more than one point.

10. Metered Quantities. The amount(s) of energy, Integrated Demands therefor and amount(s) of reactive energy delivered to the Point(s) of Delivery during each month shall be determined from measurements made by meters installed for such Point(s) of Delivery in the circuit specified.

11. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

12. Continuity of Service.

(a) The Purchaser or Bonneville may temporarily interrupt or reduce deliveries of electric power or energy if the Purchaser or Bonneville determines that such interruption or reduction is necessary or desirable in case of system emergencies, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on, the Purchaser's facilities or the Federal System. Except in case of emergency and in order that the Purchaser's operations will not be unreasonably interfered with, Bonneville shall give reasonable notice to the Purchaser of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent Bonneville has knowledge thereof. The Purchaser or Bonneville shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

(b) If the delivery of Peaking Replacement Energy or Provisional Replacement Energy to Bonneville has been interrupted or curtailed pursuant to this section, the amount of energy which would otherwise have been delivered shall be made available as soon as practicable after resumption of deliveries, upon request by Bonneville.

IN REFERENCE TO PAYMENT FOR POWER

13. Payment of Bills. Bills for power shall be rendered monthly and shall be payable at Bonneville's headquarters. Failure to receive a bill shall not release the Purchaser from liability for payment. Each calculated monetary amount in a wholesale power bill shall be rounded to a whole dollar

amount, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If Bonneville is unable to render the Purchaser a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed by the final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same payment provisions as shall a final bill.

Bills not paid in full on or before the date specified in the Payment of Bills section, or its successor, of the General Rate Schedule Provisions incorporated in the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit shall bear additional charges as specified therein.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the Purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

Bonneville may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the Purchaser, but such cancellation shall not affect the Purchaser's liability for any charges accrued prior thereto.

14. Determination of Estimated Billing Data. If the amounts of power or energy which have been delivered hereunder must be estimated from data other

than metered quantities, scheduled quantities or tabulations of hourly interchange prepared by the Purchaser, Bonneville and the Purchaser shall agree on estimated billing data to be used in preparing the bill.

IN REFERENCE TO USE OF POWER

15. Resale of Power. The Purchaser shall not resell surplus peaking capacity and surplus energy delivered under this contract except to those consumers and utilities within its service area outside the Pacific Northwest to the extent such consumers and utilities are normally dependent on the Purchaser for their firm power supplies.

16. Electric Disturbance.

(a) For the purposes of this section an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain, and use its electric system in conformance with accepted electric utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury, or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury, or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any persons not a party to this contract.

IN REFERENCE TO FACILITIES

17. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

18. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 5 hereof. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired, or replaced to provide accurate metering.

19. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

20. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment and all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other, by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and salvable facilities so installed.

21. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any

reasonable time. Such inspection, or failure to inspect, shall not render such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

MISCELLANEOUS PROVISIONS

22. General Environmental Provision.

(a) Policy. Bonneville in the performance of this contract shall comply with all of its obligations pursuant to the National Environmental Policy Act.

(b) Affirmative Obligations. The parties agree to:

(1) comply fully with all applicable Federal, State, and local environmental laws;

(2) to assist and to cooperate with each other in meeting each other's environmental obligations, to the fullest extent economically and technically practicable and mutually agreeable; and

(3) provide upon request of the other party a copy of pollution abatement plans as required by the Clean Air Act, by the Clean Water Act, by other Federal statutes, or by an agency having jurisdiction and within a reasonable time submit evidence that such plans have been approved or have not been objected to by agencies with jurisdiction.

(c) Breach of Obligations. A breach of this General Environmental Provision exists only if a final determination, including all appeals, has

been entered by a court or pollution control agency or agencies having jurisdiction that the Purchaser's facility is not in compliance with applicable laws respecting the control and abatement of environmental pollution.

(d) Remedy. Bonneville, after consulting with state or local agencies having jurisdiction may restrict delivery of surplus peaking capacity or surplus energy to the Purchaser pursuant to this contract, if Bonneville determines that:

(1) a breach of this General Environmental Provision exists;

(2) such breach is resulting in a significant adverse effect on the environment;

(3) no governmental agency has jurisdiction or authority to impose sanctions or to seek remedy for such significant adverse effect on the environment; and

(4) restriction of delivery is the only appropriate remedy and bears a reasonable relationship to the breach.

Before restricting delivery of surplus peaking capacity or surplus energy pursuant to this section, Bonneville shall give the Purchaser written notice and a reasonable opportunity to cure the breach and to seek any legal recourse available to the Purchaser.

23. Equitable Treatment of Fish and Wildlife. Constraints on operation of Federal hydroelectric facilities located on the Columbia River or its tributaries which are used to determine amounts of Surplus Energy on the Federal System include those developed for equitable treatment of fish and wildlife along with other purposes for which such system and facilities are operated and managed. Bonneville's determination of amounts of Surplus Energy

shall be based on any existing or future constraints on hydroelectric system operations.

24. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Purchaser.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the

parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 3 above;

(2) the occurrence of changes in conditions for purposes of section 4 above;

(3) the correction of the measurements to be made pursuant to section 5 above;

(4) the occurrence of an abnormal nonrecurring demand and the amount and time thereof; and

(5) whether a party has complied with section 16(b) above.

25. Net Billing. Upon mutual agreement of the parties, payments due one party may be offset against payments due the other party under all contracts between the Purchaser and Bonneville for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such

balance carried forward to be added to the payments due it in a succeeding month.

26. Contract Work Hours and Safety Standards. This contract, if and to the extent required by applicable law or if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated of Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of 8 hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work

performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

27. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by P.L. 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

28. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or

termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or workers' representative of the Contractor's commitments under the Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of subsections (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisons will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

29. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

30. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as specifically provided in this section.

31. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

32. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

33. Interest of Member of Congress. No Member of or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to such contract if made with a corporation for its general benefit.

(WP-PKI-1741c)

EXHIBIT C

P. L. 88–552

Act of August 31, 1964, 78 Stat. 756, 16 U.S.C. 837–837h
[Public No. 552 (S. 1007) – 88th Congress 2d Session]

AN ACT

To guarantee electric consumers in the Pacific Northwest first call on electric energy generated at Federal hydroelectric plants in that region and to guarantee electric consumers in other regions reciprocal priority, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That, as used in this Act —

Pacific Northwest, Federal hydroelectric plants. Definitions.

(a) "Secretary" means the Secretary of the Interior.

(b) "Pacific Northwest" means (1) the region consisting of the States of Oregon and Washington, the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming within the Columbia drainage basin and of the State of Idaho as the Secretary may determine to be within the marketing area of the Federal Columbia River power system, and (2) any contiguous areas, not in excess of seventy-five airline miles from said region, which are a part of the service area of a distribution cooperative which has (i) no generating facilities, and (ii) a distribution system from which it serves both within and without said region.

(c) "Surplus energy" means electric energy generated at Federal hydroelectric plants in the Pacific Northwest which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate.

(d) "Surplus peaking capacity" means electric peaking capacity at Federal hydroelectric plants in the Pacific Northwest for which there is no demand in the Pacific Northwest at any established rate.

(e) "Non-Federal utility" means any utility not owned or controlled by the United States, including any entity (1) which such a utility owns or controls, in whole or in part, or is controlled by, (2) which is controlled by those controlling such utility, or (3) of which such utility is a member.

(f) "Energy requirements of any Pacific Northwest customer" means the full requirements for electric energy of (1) any purchaser from the United States for direct consumption in the Pacific Northwest, and (2) any non-Federal utility in that region in excess of (i) the hydroelectric energy available for its own use from its generating plants in the Pacific Northwest, and (ii) any additional energy available for use in the Pacific Northwest which, under a then existing contract, the utility (A) can obtain at no higher incremental cost than the rate charged by the United States, or (B) is required to accept.

(g) Terms not defined herein shall, unless the context requires otherwise, have the meaning given them in the March 1949 Glossary of Important Power and Rate Terms prepared under the supervision of the Federal Power Commission. [16 U.S.C. 837.]

SEC. 2. Subject to the provisions of this Act, the sale, delivery, and exchange of electric energy generated at, and peaking capacity of, Federal hydroelectric plants in the Pacific Northwest for use outside the Pacific Northwest shall be limited to surplus energy and surplus peaking capacity. At least 30 days prior to the execution of any contract for the sale, delivery, or exchange of surplus energy or surplus peaking capacity for use outside the Pacific Northwest, the Secretary shall give the then customers of the Bonneville Power Administration written notice that negotiations for such a contract are pending, and thereafter, at any customer's request, make available for its inspection current drafts of the proposed contract. [16 U.S.C. 837a.]

Notice to purchasers.

Deliveries.

SEC. 3. (a) Any contract for the sale or exchange of surplus energy for use outside the Pacific Northwest, or as replacement, directly or indirectly, within the Pacific Northwest for hydroelectric energy delivered for use outside that region by a non-Federal utility, shall provide that the Secretary, after giving the purchaser notice not in excess of sixty days, will not deliver electric energy under such contract whenever it can reasonably be foreseen that such delivery would impair his ability to meet, either at or after the time of such delivery, the energy requirements of any Pacific Northwest customer. The purchaser shall obligate himself not to take delivery of or use any such energy to supply any load under such conditions that discontinuance of deliveries from the Pacific Northwest in sixty days would cause undue hardship to the purchaser or in his territory, and, further, the purchaser shall acknowledge full responsibility if any such hardship occurs. Deliveries by a non-Federal utility from its generating plants in the Pacific Northwest for use on its own distribution system in an area outside but contiguous to the Pacific Northwest (not including any extension of its outside service area by merger or acquisition after the effective date of this Act) shall not be deemed deliveries by such utility for use outside the Pacific Northwest.

(b) Electric energy generated at Federal hydroelectric plants in the Pacific Northwest which can be conserved, for which there is no immediate demand in the Pacific Northwest at any established rate, but for which the Secretary determines there may be a demand in meeting the future requirements of the Pacific Northwest, may be delivered for use outside that region only on a provisional basis under contracts providing that if the Secretary determines at a subsequent time that, by virtue of prior deliveries under such contract, the Secretary is or will be unable to meet the energy requirements of any Pacific Northwest customer, the purchaser will return the full amount of energy delivered to him, or such portion or portions thereof as may be required, at such time or times as may be specified by the Secretary, except that the Secretary shall not require return during the purchaser's daily peak periods. The Secretary shall require the return of the energy provisionally delivered hereunder, to such extent and at such times, as may be necessary to meet demands at any established rate for use within the Pacific Northwest.

(c) Any contract for the disposition of surplus peaking capacity shall provide that (1) the Secretary may terminate the contract upon notice not in excess of sixty months, and (2) the purchaser shall advance or return the energy necessary to supply the peaking capacity, except that the Secretary shall not require such advance or return during the purchaser's daily peak periods. The Secretary may contract for the sale of such energy to the purchaser, in lieu of its return, under the conditions prescribed in subsection (a) of this section. Contracts.

(d) The Secretary, in making any determination of the energy requirements of any Pacific Northwest customer which is a non-Federal utility having hydroelectric generating facilities, shall exclude any amounts of hydroelectric energy generated in the Pacific Northwest and disposed of outside the Pacific Northwest by the utility which, through reasonable measures, could have been conserved or otherwise kept available for the utility's own needs in the Pacific Northwest. The Secretary may sell the utility as a replacement therefor only what would otherwise be surplus energy. [16 U.S.C. 837b.]

SEC. 4. Any contract of the Secretary for the sale or exchange of electric energy generated at, or peaking capacity of, Federal hydroelectric plants in marketing areas outside the Pacific Northwest for use within the Pacific Northwest shall be subject to limitations and conditions corresponding to those provided in sections 2 and 3 for any contract for the sale or exchange of hydroelectric energy or peaking capacity generated within the Pacific Northwest for use outside the Pacific Northwest. [16 U.S.C. 837c.] Limitations.

SEC. 5. Without regard to the limitations specified in sections 2 and 3 of this Act, the Secretary may enter into contracts for the exchange with areas other than the Pacific Northwest of (1) surplus energy during the Pacific Northwest storage refill period, (2) any hydroelectric energy during the Pacific Northwest storage refill period which will be returned to the Pacific Northwest in equal amounts during the same Pacific Northwest refill period or the succeeding storage drawdown period, (3) any hydroelectric energy which will be returned to the Pacific Northwest in equal amounts during the same Pacific Northwest storage drawdown period, (4) hydroelectric peaking capacity, or (5) surplus peaking capacity for energy. All benefits from such exchanges, including resulting increases of firm power, shall be shared equitably by the areas involved, having regard to the secondary energy and other contributions made by each. [16 U.S.C. 837d.]

SEC. 6. Any capacity in Federal transmission lines connecting, either by themselves or with non-Federal lines, a generating plant in the Pacific Northwest or Canada with the other area or with any other area outside the Pacific Northwest, which is not required for the transmission of Federal energy or the energy described in section 9, shall be made available as a carrier for transmission of other electric energy between such areas. The transmission of other electric energy shall be at equitable rates determined by the Secretary, but such rates shall be subject to equitable adjustment at appropriate intervals not less frequently than once in every five years as agreed to by the parties. No contract for the transmission of non-Federal energy on a firm basis shall be affected by any increase, subsequent to the execution of such contract, in the requirements for transmission of Federal energy, the energy described in section 9, or other electric energy. [16 U.S.C. 837e.] Transmission lines.

Rates.

SEC. 7. The Secretary shall offer to amend, without imposing any other requirement as a condition to such amendment, all existing contracts for the sale or exchange of electric power generated at Federal hydroelectric plants in the Pacific Northwest to include, and shall include in all new contracts, provisions giving the purchaser priority on electric power generated at such plants in conformity with the provisions of this Act. [16 U.S.C. 837f.]

SEC. 8. No electric transmission lines or related facilities shall be constructed by any Federal agency outside the Pacific Northwest for the purpose of transmitting electric energy between the Pacific Northwest and Pacific Southwest, nor shall any arrangement for transmission capacity be executed by any Federal agency for the purpose of financing such lines and related facilities to be constructed by non-Federal entities, except those lines and facilities recommended for Federal construction in the Report of the Secretary of the Interior submitted to Congress on June 24, 1964, as supplemented on July 27, 1964, or as hereafter specifically authorized by Congress: *Provided*, That, except with respect to electric transmission lines and related facilities for the purpose of transmitting electric energy between the two regions above mentioned, nothing herein shall be construed as expanding or diminishing in any way the present authority of the Secretary of the Interior to construct transmission lines to market power and energy. [16 U.S.C. 837g.]

Applicability.

SEC. 9. The provisions of this Act shall not be applicable to (1) the Canyon Ferry project and (2), except as provided in section 6, downstream power benefits to which Canada is entitled under the treaty between Canada and the United States relating to the cooperative development of the water resources of the Columbia River Basin, signed at Washington, January 17, 1961, nor to energy or capacity disposed of to Canada in any exchange pursuant to paragraph 1 or 2 of article VIII thereof. Nothing in this Act shall be construed to modify the geographical preference of power users in the State of Montana which is established by the Hungry Horse Dam Act (Act of June 4, 1944 [So in original; should be June 5, 1944], 58 Stat. 270), as amended. [16 U.S.C. 837h.]

CITY OF RIVERSIDE

Minutes of Regular Meeting of the City Council
Date of Meeting: March 20, 1990
Time of Meeting: 9 A.M.
Place of Meeting: Council Chamber, City Hall

	COUNCILMEMBERS						
WARDS	LOVERIDGE 1	CLARKE 2	MANSFIELD 3	BUSTER 4	OSBORNE 5	THOMPSON 6	7
Present	X	X	X	X	X	X	X
Motion		X					
Second				X			
All Ayes							

Roll Call:

FIRM PEAKING CAPACITY SALE/EXCHANGE AGREEMENT WITH BONNEVILLE POWER ADMINISTRATION

A written report was submitted from the City Manager and the Public Utilities Director, concurred in by the City Attorney, recommending that the City Council authorize execution of a Firm Peaking Capacity Sale/Exchange Agreement between Bonneville Power Administration and the City of Riverside. Following discussion, the recommendation was approved as presented.

Certified under penalty of perjury to be a full, true and correct excerpt from the Minutes of the City Council appearing on Page 75-386, on file in my office.

Alice A. Hare
City Clerk of the City of Riverside

Dated this 9th day of April, 1990, at Riverside, CA.

Contract No. DE-MS79-94BP93958
05/20/94

AUTHENTICATED

1996 DIVERSITY EXCHANGE AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
RIVERSIDE, CALIFORNIA

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This 1996 DIVERSITY EXCHANGE AGREEMENT (Agreement) is executed as of July 5th 1994, by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville"), and the CITY OF RIVERSIDE, CALIFORNIA ("Riverside"), a municipal corporation of the State of California. Bonneville and Riverside are hereinafter sometimes referred to individually as "Party" and collectively as "Parties".

W I T N E S S E T H:

WHEREAS Bonneville sells electric capacity and energy at wholesale, and projects availability of amounts in excess of its existing obligations to deliver such capacity and energy to its Pacific Northwest customers; and

WHEREAS Riverside is the owner of an electric generation, transmission and distribution system which it uses to supply capacity and energy to its customers and other utilities; and

WHEREAS the Parties have entered into an agreement which, among other things, provides for the exchange of capacity for energy and for a capacity sale by Bonneville (Contract No. DE-MS79-90BP92858), and the Parties desire to enter into arrangements which provide for additional exchanges; and

WHEREAS Riverside has entered into, or intends to enter into, one or more agreements which provide for transmission service on the DC Intertie between the Nevada-Oregon border and Riverside's electric system; and

WHEREAS Riverside intends to enter into an agreement with the Southern California Edison Company (SCE) which provides for the integration of capacity and energy acquired pursuant to this Agreement (SCE-Riverside Supplemental Integration Agreement); and

WHEREAS Bonneville is authorized pursuant to law to dispose of surplus electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission

facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. EFFECTIVE DATE AND TERM

(a) **Effective Date**

Unless otherwise agreed, this Agreement shall become effective at 0001 hours on the first day of the first month after the occurrence of all the following events (Effective Date):

(1) execution of this Agreement by both Parties; and

(2) the effective date of the Transmission Service Agreement, or, if Riverside should enter into more than one Transmission Service Agreement to provide for deliveries hereunder, the latest effective date of such agreements; and

(3) the effective date of the SCE-Riverside Supplemental Integration Agreement; and

(4) April 30, 1996.

(b) **Term**

This Agreement shall remain in full force and effect until the earlier of:

(1) 2400 hours on the anniversary date twenty (20) years after the Effective Date; or

(2) the date the Transmission Service Agreement terminates, or, if Riverside has entered into more than one Transmission Service Agreement to provide for deliveries hereunder, the earliest termination date of any such agreements unless first replaced by other agreements or other suitable arrangements; or

(3) the date the Edison-Riverside Supplemental Integration Agreement terminates unless first replaced by other agreements or other suitable arrangements.

All obligations incurred hereunder prior to termination shall be preserved until satisfied.

2. DEFINITIONS

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified.

(a) "Calendar Week" means the week beginning at 0001 hours on Sunday and ending at 2400 hours on the following Saturday.

(b) "Contract Demand" means the applicable maximum hourly rate of delivery for Firm Peaking Capacity specified in section 4(a).

(c) "Contract Year" means the period beginning at 0001 hours on May 1 and ending at 2400 hours the following April 30.

(d) "DC Intertie" means the direct-current 1000 kilovolt extra high voltage electric transmission line between Bonneville's Celilo Substation, located in The Dalles, Oregon, and the Los Angeles Department of Water and Power's Sylmar Switching Station, located in Sylmar, California.

(e) "Delivery Season" means the period beginning at 0001 hours on November 1 and ending at 2400 hours on the following April 15.

(f) "Energy Account" means an account consisting of Exchange Energy, Seasonal Return Energy and Peaking Replacement Energy, the delivery of which has been deferred pursuant to section 4(d), 5(b) or 7(b).

(g) "Exchange Energy" means the energy Riverside is obligated to deliver to Bonneville in exchange for Bonneville deliveries of Firm Peaking Capacity.

(h) "Firm Peaking Capacity" means the capacity delivered by Bonneville to Riverside pursuant to this Agreement.

(i) "Firm Peaking Energy" means the energy delivered by Bonneville to Riverside associated with Bonneville's deliveries of Firm Peaking Capacity during the Summer Season and Winter Season.

(j) "Off-peak Hours" means all other hours which are not On-peak Hours as defined in section 2(k).

(k) "On-peak Hours" means the following hours:

(1) 0900 to 2300 hours Monday through Friday, excluding holidays, during the period of May 1 through October 31; and

(2) 0800 to 2200 hours Monday through Friday, excluding holidays, during the period November 1 through April 30.

(l) "Outage" means an interruption or curtailment of deliveries due to a reduction, including to zero, of available DC Intertie transmission capacity due to physical or operating limitations.

(m) "Peaking Replacement Energy" means the energy which Riverside is obligated to deliver to Bonneville, pursuant to section 5, to replace Firm Peaking Energy delivered during the Summer Season and the Winter Season.

(n) "Point of Delivery" means the point(s) where deliveries of capacity and energy between the Parties takes place pursuant to section 8.

(o) "Seasonal Firm Energy" means the energy delivered by Bonneville to Riverside associated with Bonneville's deliveries of Firm Peaking Capacity during the Spring Season.

(p) "Seasonal Return Energy" means the energy Riverside is obligated to deliver to Bonneville, pursuant to section 4(c), in exchange for Bonneville deliveries of Seasonal Firm Energy the preceding Spring Season.

(q) "Spring Season" means the period beginning at 0001 hours on May 1 and ending at 2400 hours the following June 30.

(r) "Summer Season" means the period beginning at 0001 hours on July 1 and ending at 2400 hours on the following October 31.

(s) "Total Incremental Cost" means the sum of the incremental fuel cost, incremental operation and maintenance cost, generating unit start-up cost, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Riverside in supplying Exchange Energy to Bonneville, including transmission losses incurred by Riverside in delivering Exchange Energy to the Point of Delivery, that would not otherwise have been incurred but for Bonneville's purchase of Exchange Energy pursuant to section 7(d).

(t) "Transmission Service Agreement" means any agreement entered into by Riverside and a third party whereby Riverside acquires transmission service for deliveries in accordance with this Agreement.

(u) "Uncontrollable Force" means any act or event beyond the control of a Party which adversely affects the ability of the Party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid, including, but not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning, and other natural catastrophes, epidemic, war, labor or material shortage, strike or labor dispute, or sabotage, and restraint by court order or by regulatory authorities; and, after a good faith effort by the affected Party to so obtain, action or nonaction by or failure to obtain the necessary authorizations or approvals from any governmental agency or regulatory authority.

(v) "Winter Season" means the period beginning at 0001 hours on November 1 and ending at 2400 hours on the following April 30.

(w) "Workday" means each day which both Bonneville and Riverside observe as a regular day of work.

3. EXHIBITS

Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), Bonneville's General Contract Provisions, Form PSC (SW-1) (Exhibit B), 16 U.S.C. Section 837 (1984) (Public Law 88-552) (Exhibit C), and the IPA Monthly Budget Summary for Riverside as contained in the Final Operating Budget for the Intermountain Power Project (Exhibit D) are attached hereto and hereby made a part of this Agreement. In the event a provision of Exhibit A or B conflicts with sections 1 through 18 of this Agreement, then the provisions of sections 1 through 18 of this Agreement shall control. In the event a provision in Exhibit B conflicts with a provision of Exhibit A, then the provision in Exhibit A shall control.

4. CAPACITY FOR ENERGY EXCHANGE

(a) **Contract Demand**

Bonneville shall make available to Riverside Firm Peaking Capacity each hour in an amount equal to the applicable Contract Demand.

(1) From the Effective Date through April 30, 1998, the Contract Demand during the Spring Season and Summer Season shall be fifty (50) megawatts (MW), and the Contract Demand during the Winter Season shall be thirteen (13) MW.

(2) From May 1, 1998 through the end of the term of this Agreement, the Contract Demand during the Spring Season and Summer Season shall be sixty (60) MW, and the Contract Demand during the Winter Season shall be fifteen (15) MW.

(b) **Energy Deliveries by Bonneville**

(1) During the Winter Season and Summer Season, Firm Peaking Energy shall be delivered by Bonneville pursuant to the scheduling provisions of section 9, in daily amounts, including holidays, up to six (6) megawatthours (MWh) per MW of the applicable Contract Demand, and in Calendar Week amounts up to thirty (30) MWh per MW of the applicable Contract Demand.

(2) During the Spring Season, Riverside shall be obligated to schedule Seasonal Firm Energy as follows, unless otherwise agreed by the Parties' schedulers or dispatchers:

(A) From the Effective Date through April 30, 1998, fifty (50) MW for six (6) hours during each weekday, and fifteen (15) MW for each remaining hour during such season; and

(B) After April 30, 1998, sixty (60) MW for six (6) hours during each weekday, and eighteen (18) MW for each remaining hour during such season.

(c) **Energy Deliveries by Riverside**

(1) Riverside shall, in return for Firm Peaking Capacity made available during the current Contract Year and Seasonal Firm Energy delivered by Bonneville during the preceding Spring Season, deliver Exchange Energy and Seasonal Return Energy to Bonneville each Delivery Season as provided herein.

(A) The amount of Exchange Energy provided shall equal the exchange ratio in MWh/MW multiplied by the applicable Contract Demand during each month of the Summer Season and the Winter Season. The exchange ratio shall be one hundred and ninety five (195) MWh/MW per month.

(B) The amount of Seasonal Return Energy shall equal the amount of Seasonal Firm Energy delivered during the previous Spring Season.

(2) Exchange Energy and Seasonal Return Energy shall be delivered during Off-peak Hours in equal weekly increments during the Delivery Season, unless otherwise agreed by the Parties' schedulers or dispatchers.

(3) During the period of September 1 through October 31 of each Contract Year, Riverside may predeliver Exchange Energy and Seasonal Return Energy in amounts agreed to by the Parties. Any such predeliveries shall be at times and at rates of delivery agreed to by the Parties' schedulers and/or dispatchers. Riverside may also predeliver Exchange Energy and Seasonal Return Energy during the Delivery Season in amounts agreed to by the Parties. Any Exchange Energy and/or Seasonal Return Energy delivered during times, or in amounts, other than as provided in section 4(c)(2) shall only serve to reduce the length of the Delivery Season and shall not reduce the weekly amount of such energy Riverside would otherwise deliver.

(d) **Exchange Energy and Seasonal Return Energy Delivery Limitations**

(1) Unless otherwise agreed, the maximum hourly rate of delivery for Exchange Energy and Seasonal Return Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, shall equal the maximum Contract Demand during the current Contract Year.

Upon agreement of the Parties' schedulers, and subject to Riverside making arrangements for additional intertie capacity or counter-scheduling against a Bonneville delivery to Riverside:

(A) during the months of November, December, January, and February, the maximum hourly rate of delivery for Exchange Energy and Seasonal Return Energy, when combined with

other deliveries by Riverside to Bonneville under this Agreement, shall be two hundred percent (200%) of the maximum Contract Demand for the current Contract Year; and

(B) during the months of March and April, the maximum hourly rate of delivery for Exchange Energy and Seasonal Return Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, shall be one hundred thirty percent (130%) of the maximum Contract Demand for the current Contract Year.

(2) Subject to Outages, and unless limited by Bonneville pursuant to sections 4(d)(3) and 4(d)(4), Riverside shall complete each Calendar Week's obligation to deliver Exchange Energy and Seasonal Return Energy by the end of such Calendar Week.

(3) At the time schedules for the delivery of Exchange Energy and Seasonal Return Energy are established by Riverside pursuant to section 9, Bonneville may limit the hourly delivery rate for Exchange Energy and Seasonal Return Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, to not less than sixty percent (60%) of the maximum Contract Demand for the current Contract Year.

(4) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Exchange Energy and Seasonal Return Energy, including down to zero (0).

(5) To the extent that Bonneville restricts the delivery of Exchange Energy and/or Seasonal Return Energy,

(A) Bonneville may place such energy into the Energy Account provided for in section 6; or

(B) the Parties may mutually agree to delay the delivery of such energy.

5. PEAKING REPLACEMENT ENERGY

(a) **Obligation to Deliver**

Subject to sections 5(b) and 7(b), Riverside shall deliver Peaking Replacement Energy to Bonneville each day in an amount equal to the amount of Firm Peaking Energy delivered by Bonneville the preceding day. Unless otherwise agreed by the Parties' schedulers and dispatchers, deliveries of Peaking Replacement Energy shall be limited to Off-peak Hours.

(b) **Peaking Replacement Delivery Limitations**

(1) Unless otherwise agreed, the maximum hourly rate of delivery of Peaking Replacement Energy, when combined with other deliveries by Riverside to Bonneville under this Agreement, shall be equal to the maximum Contract Demand for the current Contract Year.

(2) At the time schedules for the delivery of Peaking Replacement Energy are established by Riverside pursuant to section 9, Bonneville may limit the hourly delivery rate for Peaking Replacement Energy to not less than sixty percent (60%) of the maximum Contract Demand for the current Contract Year, rounded to the nearest whole megawatt.

(3) If Bonneville provides notice to Riverside by 1400 hours on the Thursday preceding a Calendar Week, Bonneville may specify the days and hours of the upcoming Calendar Week during which Bonneville limits deliveries of Peaking Replacement Energy, including down to zero (0).

(4) To the extent that Bonneville restricts the delivery of Peaking Replacement Energy,

(A) Bonneville may place such energy into the Energy Account provided for in section 6; or

(B) the Parties may agree to delay the delivery of such energy.

6. ENERGY ACCOUNT

(a) Upon the Effective Date of this Agreement, an Energy Account will be established and maintained by Bonneville which shall contain the deferred amounts of Peaking Replacement Energy, Exchange Energy and Seasonal Return Energy credited to such account pursuant to this Agreement.

(b) Subject to this section 6(b), Bonneville may withdraw energy from the Energy Account during a Calendar Week by providing Riverside with notice by 1400 hours on the Thursday prior to such Calendar Week, specifying the weekly quantity of energy to be withdrawn, and the rate(s) of delivery for such energy.

(1) Unless otherwise mutually agreed, the rate(s) of delivery shall not exceed the maximum Contract Demand for the current Contract Year, and the times of delivery shall be Off-peak Hours.

(2) Such withdrawals shall not cause Riverside to defer or otherwise limit deliveries of Exchange Energy, Seasonal Return Energy or Peaking Replacement Energy. Riverside shall deliver energy as requested pursuant to this section 6(b) during the Delivery Season from the Energy Account, subject to Outages. Withdrawals from the Energy Account at times other than during the Delivery Season shall be by agreement of the Parties' schedulers.

(3) After April 15, and at Bonneville's request, the Parties shall attempt in good faith to develop a mutually agreeable plan for the delivery of any energy remaining in the Energy Account. If the Parties are unable to agree on a plan, and such energy is not delivered by the following September 30, the energy shall be cashed out pursuant to section 6(c).

(c) Each October 1, energy remaining in the Energy Account shall be cashed-out. The cash-out price for such energy shall be the lesser of (1) Bonneville's contract rate specified in Bonneville's then effective nonfirm rate schedule or (2) the average incremental energy rate paid by Riverside for energy from the Intermountain Power Project, which shall be adjusted by increasing the rate twelve and three-tenths percent (12.3%), during the previous Delivery Season, as specified in Exhibit D. Riverside shall be relieved of any obligation to provide energy to Bonneville to the extent the energy is cashed out.

Riverside shall provide Bonneville with a copy of the IPA Monthly Budget Summary for each fiscal year no later than October 1 of each year. The new IPA Monthly Budget Summary shall be attached to this Agreement as a revised Exhibit D, and shall be applicable to the next Delivery Season. Riverside shall mail the revised IPA Monthly Budget Summary to:

Chief, Interchange Scheduling Section - PSKI
United States Department of Energy
Bonneville Power Administration
P.0. Box 3621
Portland, OR 97208-3621

7. TRANSMISSION LIMITATIONS

(a) In the event of an interruption of deliveries by either Party due to an Outage, transactions under this Agreement will have priority over any competing nonfirm energy transaction of Riverside and Bonneville.

(b) Following periods of an Outage, Riverside shall continue to be obligated to deliver Exchange Energy, Seasonal Return Energy and Peaking Replacement Energy. Both Parties shall use best efforts to reschedule interrupted or curtailed deliveries of such energy under conditions approximately equivalent to the conditions existing prior to the Outage; **provided**, that in rescheduling such energy, Riverside shall not exceed the delivery limits set forth in sections 4(d) and 5(b), unless otherwise agreed. The Parties may also agree to reschedule delivery at other times and under conditions other

than those existing prior to the Outage. To the extent the Parties have not rescheduled such energy within sixty (60) days following the end of the Outage, the Energy Account shall be credited for any such amounts of energy.

(c) **Exchange Energy Relief**

If during any month the availability of Firm Peaking Energy during On-peak Hours is less than eighty-five percent (85%) due to one or more Outages, Riverside shall be excused from delivering an amount of Exchange Energy determined by subtracting the actual percentage of Firm Peaking Energy availability during the On-peak Hours from eighty-five percent (85%), and multiplying the result by the quantity of Exchange Energy Riverside would otherwise deliver for Firm Peaking Capacity made available during such month; **provided**, that Bonneville may elect to purchase, pursuant to section 7(d), Exchange Energy which Riverside would otherwise be excused from delivering pursuant to this section 7(c).

(1) Riverside shall notify Bonneville and request a reduction in Riverside's Exchange Energy obligation when such reduction is warranted pursuant to this section.

(2) Any reduction in Riverside's Exchange Energy obligation shall be met by decreasing the length of the Delivery Season rather than adjusting the weekly amounts of Exchange Energy to be delivered by Riverside.

(3) If Riverside delivers to Bonneville more than its Exchange Energy obligation for any Contract Year, Riverside may elect to:

(A) reduce its Exchange Energy obligation for the next Contract Year; or

(B) use such energy to reduce its Peaking Replacement Energy obligations at times and rates of delivery agreed to by the Parties' schedulers or dispatchers; or

(C) if agreed to by Bonneville, cashout such energy at the rate determined pursuant to section 6(c).

(d) **Bonneville Purchase of Exchange Energy**

Bonneville may elect to purchase Exchange Energy which Riverside otherwise would be excused from delivering pursuant to section 7(c) as follows:

(1) Bonneville shall notify Riverside at least one (1) month prior to requesting delivery of such Exchange Energy.

(2) Within ten (10) Workdays after receipt of Bonneville's notice requesting Exchange Energy, and prior to Riverside committing to obtain energy with which to supply Exchange Energy, Riverside shall inform Bonneville of the probable lowest cost resources available to supply such requested Exchange Energy, including the estimated Total Incremental Cost of such resources. If conditions change substantially, Riverside shall revise the estimated Total Incremental Cost.

(3) Bonneville shall provide Riverside with at least one (1) Calendar Week's final written notice prior to the start of each Calendar Week's deliveries whether Bonneville shall require Riverside to deliver the Exchange Energy, or whether Bonneville relieves Riverside of the obligation to deliver that Calendar Week's Exchange Energy.

(4) For all deliveries of Exchange Energy pursuant to this section 7(d), Bonneville shall pay Riverside the Total Incremental Cost of the Exchange Energy for the first three (3) months of deliveries, and one hundred fifteen percent (115%) of Riverside's Total Incremental Cost for all Exchange Energy delivered after three (3) months pursuant to this section 7(d).

8. POINTS OF DELIVERY

Deliveries shall be at the point where the DC Intertie crosses the Nevada-Oregon border, or the point(s) where the 500 kV alternating current transmission line(s)

between Oregon and California cross the California-Oregon border, or at such other points as agreed by the Parties.

9. SCHEDULING PROVISIONS

Submission of all schedules between Bonneville and Riverside, or its agent, for delivery of capacity and energy hereunder shall be subject to the following provisions unless otherwise agreed by the Parties' schedulers or dispatchers, or their agents as designated by a Party to act on its behalf:

(a) Preschedules shall be completed by 0930 hours on each Workday and shall be effective for each hour of the following day, or days, through the next Workday. Each Party, or its agent shall endeavor to avoid requesting changes in prearranged schedules. Changes in preschedules shall be submitted no later than thirty (30) minutes before the hour, for which the change is to be effective, emergencies excepted.

(b) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts of Firm Peaking Energy or Seasonal Firm Energy that Riverside, or its agent, anticipates it will schedule from Bonneville each day for the following ten (10) days. Riverside, or its agent, shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Riverside, or its agent, or Bonneville to schedule such amounts.

10. PAYMENT

Each Party shall pay the other Party in accordance with this Agreement upon receipt of properly documented bills. Bills submitted by Riverside must reference this contract number and be sent to:

United States Department of Energy
Bonneville Power Administration
Chief, Program and Contracts Review Section - DSAC
P.O. Box 3621
Portland, OR 97208-3621

Bills submitted by Bonneville must reference this contract number and be sent to:

City of Riverside
Central Cashiering
3900 Main Street
Riverside, CA 92522

All payments shall be rendered by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than its mailing date. Should the twentieth (20th) day be a Saturday, Sunday, or holiday, then the due date shall be the next following business day. Payment of bills shall be in accordance with Exhibits A and B, attached hereto.

11. UNCONTROLLABLE FORCES

(a) Obligations of the Parties, other than those to pay money under section 10, shall be excused when failure to perform such obligations is due to an Uncontrollable Force; provided, however, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability with reasonable dispatch. Nothing in this section 11 shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(b) Each Party shall notify the other as soon as possible of any Uncontrollable Force which may adversely affect performance under this Agreement. Failure of a Party to give notice to the other Party shall not be deemed a waiver of such Uncontrollable Force.

(c) For purposes of this section 11, an Outage of less than one (1) year shall not be considered an Uncontrollable Force.

12. ASSIGNMENT OF AGREEMENT

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

13. NOTICES

Unless the Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in

writing and shall be deemed properly served, given, or made if delivered in person or sent by telegraph, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:

To Riverside:	Public Utilities Director City of Riverside 3900 Main Street Riverside, CA 92522
To Bonneville:	Assistant Administrator for Power Sales - P United States Department of Energy Bonneville Power Administration P.0. Box 3621 Portland, OR 97208-3621

Either Party may, by written notice to the other Party, change the designation or address of the person so specified as the one to receive notices pursuant to this Agreement.

14. DISPUTES

Pending resolution of any disputed matter, the Parties shall continue performance of their respective obligations pursuant to this Agreement. The Parties shall discuss disputes regarding any matter relating to this Agreement, and shall use their best efforts to amicably and promptly resolve each such dispute.

15. AUDITS

Each Party shall have the right to audit and to examine any cost, payment, settlement or supporting documentation, including, but not limited to, audit reports, resulting from any items set forth in this Agreement. Any such audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The Party being audited shall cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of five (5) years following the first billing for such cost under this Agreement. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period.

The Party being audited shall be notified in writing of any exception taken as a result of an audit promptly after completion of the audit. The Party being audited shall have thirty (30) days to review the notice of exception.

(a) If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) to the other Party, with interest calculated in the same manner as in Exhibits A and B, or their successors, within ten (10) days after agreement is reached.

(b) If the Parties dispute any exception(s) taken as a result of the audit, the owing Party shall so notify the other Party in writing promptly after its receipt of the written notification of exception. Such dispute shall then be subject to the provisions set forth in section 14. If upon resolution of the dispute, it is determined that a Party shall make payment to the other Party, such payment shall be made within ten (10) days of resolution of the dispute, with interest calculated in the same manner as set forth in Exhibits A and B, or their successors.

16. GOVERNING LAW

This Agreement shall be interpreted, governed by and construed under Federal law applicable to Bonneville.

17. WAIVERS

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement shall be waived except in writing. Any waiver at any time by a Party of its rights with respect to a default under this Agreement, or any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter.

18. SIGNATURE CLAUSE

The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ WALTER E. POLLOCK
Assistant Administrator
for Power Sales

Name Walter E. Pollock
(Print / Type)

Date August 12, 1994

CITY OF RIVERSIDE, CALIFORNIA

By /S/ JOHN E. HOLMES

Name John Holmes
(Print / Type)

Title City Manager

Date July 5, 1994

(PMLAN-PMCN-W:\PMC\CT\93958\93958.DOC)

TMC QA Contracts Documentation Checklist Procedure

NOTE: It's the Contract Specialist's (CS) responsibility to double-check their work as it is finalized. The Quality Assurance Team (QA) is reviewing documents as a final independent check for accurate content and technical validity prior to the contract action documents being handed to TM for signature. It is not intended to replace the CS' own accuracy check.

The CS initiates the QA Checklist. It should be submitted to the QA Team member **TWO** (2) days in advance of the desired signature date, together with the required supporting documents. Documents should be submitted in **FINALIZED** condition for review. If an item is not relevant, write "N/A". If there are multiple OASIS Request Queue and/or AREF numbers, include them all. Attach a copy of the OASIS 'Flat File' posting for all referenced Request #s. ***Customer Response Deadline***: If the document is governed by a Tariff response deadline, write in the date of that deadline. ***Documentation creation process*** **- From Template/Re-edit -** any document that is **NOT** created ***directly*** from a template is considered a re-edit

Step 1: CS checks (✓) each line as it is completed. Use N/A as appropriate. If OGC review is required, this should be complete ***PRIOR TO*** submission to QA and supporting documentation attached. CS must ensure that contract action has required authorization and sign-off prior to implementation. **NOTE**: Some line items require the attachment of supporting documentation.

Step 2 and 3: TCMS Group completes a review of the contract document and cover letter. The TCMS Group must certify that the documents are formatted consistent with BPA and TBL guidelines, are free from errors and omissions, meet BPA's Records Management policies, and are processed in a manner consistent with BPA and TBL guidance (policies, procedures, and practices).

Step 4: QA Team member certifies that all information provided by the CS is accurate.

AUTHENTICATED

Contract No. DE-MS79-94BP93658
03/14/94

CAPACITY FOR ENERGY EXCHANGE AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
THE CITY OF PASADENA

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This CAPACITY FOR ENERGY EXCHANGE AGREEMENT, executed as of **JUNE 29th**, 19**94**, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and the CITY OF PASADENA, CALIFORNIA (Pasadena), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

WITNESSETH:

WHEREAS Pasadena is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Pasadena, the City of Burbank (Burbank), the City of Glendale (Glendale), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which provided, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Pasadena, Burbank, and Glendale; and

WHEREAS on January 28, 1988, Pasadena and Bonneville executed Contract No. DE-MS79-87BP92413 (Sale and Exchange Agreement) which provides, among other things, for a power sale by Bonneville to Pasadena that converts to a capacity for energy exchange pursuant to certain terms and conditions; and

WHEREAS this Agreement, the Sale and Exchange Agreement, and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Bonneville and Pasadena have agreed to enter into a seasonal capacity for energy exchange under the terms and conditions set forth herein; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. TERM

This Agreement, when executed, shall become effective at 0001 hours on May 1, 1995, and shall continue in effect until 2400 hours on April 30, 2015, **provided, however**, that either Party may terminate this Agreement effective any time after May 1, 2004, by providing the other Party with four (4) years' written notice. Notwithstanding the foregoing, this Agreement shall not become effective

until the Pacific Northwest-Pacific Southwest DC Intertie transmission facilities, including the Sylmar Converter Station, are restored to full transfer capability (north to south and south to north), unless otherwise mutually agreed by the Parties. All obligations incurred hereunder shall be preserved until satisfied.

2. DEFINITIONS

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

(a) "Agreement" means this capacity for energy exchange agreement between Bonneville and Pasadena, Contract No. DE-MS79-94BP93658.

(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

(c) "Contract Demand" means the maximum hourly rate of delivery for capacity service. This amount is equal to 15 MW.

(d) "Contract Year" means the year beginning at 2400 hours on April 30 and ending at 2400 hours on the following April 30.

(e) "Exchange Energy" means the energy Pasadena is obligated to deliver to Bonneville during each September through March 15 period in exchange for capacity service made available by Bonneville during the preceding May through September period.

(f) "Heavy Load Hours (HLH)" means all hours other than LLH.

(g) "Light Load Hours (LLH)" means the first eight (8) hours and the last two (2) hours daily, Monday through Saturday, and all hours on Sunday.

(h) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie (Intertie) transmission lines cross the Nevada-Oregon border.

(i) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Pasadena.

(j) "Peaking Replacement Energy" means an amount of energy which Pasadena is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

(k) "Prudent Utility Practice" means those practices, methods, and equipment, including provisions for contingencies and reserves, that are commonly used to plan and operate electric power facilities reliably and safely to serve a utility's customers dependably and economically, with due regard for the state of the art in the electric power industry as practiced by major electric utilities which are members of the Western Systems Coordinating Council or successor organization.

(l) "Uncontrollable Force" means any act or event beyond the control of a Party which impairs the ability of the party to perform, which by exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to avoid. Uncontrollable Force includes, but it is not limited to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning and other natural catastrophes, epidemic, war, riots, labor or material shortage, strike or labor dispute, or sabotage; and also includes restraint by an order of a court of competent jurisdiction or by regulatory authorities, against an action taken or not taken by a Party, after a good faith effort by the appropriate Party (1) to obtain relief from such order, or (2) to obtain any necessary authorizations or approvals from any governmental agency or regulatory authority.

(m) "Workday" means each day which both Bonneville and Pasadena observe as a regular day of work.

3. EXHIBITS

Exhibit A (GCP Form PSC(SW)-1, dated 11/3/83) is attached hereto and hereby made a part of this Agreement. In the event of a conflict between the body of this Agreement and Exhibit A, the body of this Agreement shall prevail.

4. SERVICE TO PASADENA

(a) **Service to Pasadena During May and June**

During the months of May and June, Bonneville shall make Peaking Energy available to Pasadena. Pasadena may preschedule such Peaking Energy at an hourly rate of delivery not to exceed 15 MW during any hour. Pasadena shall schedule no less than 1,630 MWh during the month of May, and no less than 1,630 MWh during the month of June. Pasadena shall not deliver any Peaking Replacement Energy to Bonneville during this period, but shall return such energy during the following September through March 15 period, as provided for in section 5 below.

(b) **Service to Pasadena During July, August, and September**

(1) **Deliveries of Peaking Energy by Bonneville**

Bonneville shall deliver Peaking Energy to Pasadena during each July, August, and September in amounts not to exceed 15 MWh during any hour, and not to exceed 150 MWh during any day. Peaking Energy shall be delivered in Calendar Week amounts not to exceed 750 MWh during any week.

(2) **Deliveries of Peaking Replacement Energy by Pasadena**

Pasadena shall deliver Peaking Replacement Energy to Bonneville in an amount equal to the amount of Peaking Energy delivered to Pasadena. Such Peaking Replacement Energy shall be delivered by 2400 hours on the day following Bonneville's delivery of such Peaking Energy, at a rate of delivery not to exceed 15 MW during any hour, unless otherwise agreed to by the Parties.

(3) Hourly deliveries of Peaking Replacement Energy by Pasadena during July, August, and September shall be considered nonfirm by both Parties. For the purposes of this Agreement, "nonfirm" means that the schedule may be reduced with an oral notice by either Party at least thirty minutes prior to the start of the hour of the reduction. Deliveries reduced under this section shall be rescheduled at times and rates as agreed to by the Parties.

(4) All Peaking Replacement Energy will be prescheduled pursuant to section 6.

5. SERVICE TO BONNEVILLE

(a) Service to Bonneville During the September Through March 15 Period

(1) Exchange Energy

In exchange for capacity service made available by Bonneville during May through September, Pasadena shall deliver to Bonneville during LLH, unless otherwise agreed, and subject to adjustment pursuant to section 8(d), an amount of Exchange Energy equal to:

Delivery Period	Exchange Energy Obligation
September 1 through March 15	16,500 MWh

(2) May-June Peaking Replacement Energy

In addition to the Exchange Energy obligation described in section 5(a)(1), Pasadena shall deliver to Bonneville during LLH, unless otherwise agreed, and subject to adjustment pursuant to section 8(c), a minimum amount of Peaking Replacement Energy equal to:

Delivery Period	Peaking Replacement Energy Obligation
September 1 through March 14	3,260 MWh (minimum)

To the extent that Pasadena schedules amounts greater than the 3,260 MWh minimum during any May-June period, the 3,260 MWh shall be increased to reflect such additional amounts of Peaking Replacement Energy.

(b) **Rate of Delivery**

The rate of delivery for Exchange Energy and Peaking Replacement Energy, individually or in combination, pursuant to sections 4(b)(2), 5(a)(1), and 5(a)(2) shall be as mutually agreed by the Parties. Except as provided in section 5(c), Bonneville shall accept such energy as scheduled by Pasadena at the mutually agreed upon rate of delivery, and such rate shall not be less than 15 MW when scheduled.

(c) Exchange Energy deliveries, pursuant to section 5(a), shall be considered firm by the Parties for the September through March 15 period. Such energy is to be firm for such period, however, it is "nonfirm" on any hour, as "nonfirm" is described in section 4(b)(3). For the purposes of this section 5(c) "firm" means that the Parties shall use best efforts to deliver all Exchange Energy by March 15 of each year. Deliveries that are curtailed shall be rescheduled at times and rates as agreed to by the Parties.

(d) All Exchange Energy will be prescheduled pursuant to section 6.

6. SCHEDULING PROVISIONS

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

(b) Hourly preschedules shall be submitted by 0930 hours.

(c) By 1200 hours on any Wednesday, Bonneville may request estimates of the hourly amounts that Pasadena anticipates it will schedule from Bonneville each day for the following five (5) days. Pasadena shall submit such estimates to Bonneville by 1200 hours on the first Workday following Bonneville's request. Such estimates are for the purpose of information only and shall not obligate either Pasadena or Bonneville to schedule such amounts.

(d) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such requested changes shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

7. FORCE OUT ENERGY

If by 2400 hours on the 15th day of March each year Pasadena has been unable to deliver all Exchange Energy and/or Peaking Replacement Energy which Pasadena is obligated to return under section 5(a), or Bonneville has been unable to receive such energy, then Pasadena shall preschedule the energy balance (Force Out Energy) for delivery during LLH beginning at 2400 hours on the 15th day of March until the balance of such Force Out Energy due to be delivered by Pasadena to Bonneville is zero.

Unless otherwise mutually agreed, the minimum rate of delivery for Force Out Energy shall be 15 MW until the remaining balance is less than 15 MWh. Such remaining balance shall be delivered on the next LLH.

Deliveries of Force Out Energy shall be considered firm by both Parties.

8. TRANSMISSION LIMITATIONS

(a) **Peaking Energy Curtailments**

At any time, Bonneville may curtail deliveries of Peaking Energy for necessary maintenance, or to protect Bonneville's system during operational constraints beyond its reasonable control due to unexpected instability or thermal limitation for equipment or line outages, disturbances on the Federal Columbia River Transmission System (FCRTS), disturbances on the system of an interconnected utility, or other unexpected adverse system conditions. To the extent any line limitation due to forced outage or forced capacity reduction of the Intertie precludes Bonneville from delivering Peaking Energy, Bonneville shall be relieved of its obligation to deliver the Peaking Energy during the period of the above conditions or line limitations.

(b) **Exchange Energy or Peaking Replacement Energy Curtailments**

If Pasadena is unable to deliver, or Bonneville is unable to accept, scheduled Peaking Replacement Energy or Exchange Energy due to any necessary maintenance or cause which is beyond their reasonable control, including transmission or generation limitations, delivery of energy shall be curtailed to the extent necessary until such cause has been removed or ends. Deliveries reduced under this section 8(b) shall be rescheduled pursuant to section 6 at such times and rates as agreed by the Parties.

(c) **Peaking Replacement Energy Relief**

If during any May or June Pasadena is unable to receive the minimum Peaking Energy specified in section 4(a) due to transmission outages, then Pasadena shall be excused from delivering an amount of Peaking Replacement Energy equal to 3,260 MWh less the amount received.

(d) **Exchange Energy Relief**

If during any month Pasadena is unable to receive at least eighty-five percent (85%) of the Peaking Energy specified in section 4(b)(1) due to one or more transmission outages, Pasadena shall be excused from delivering an amount of Exchange Energy determined by subtracting the actual percentage of Peaking Energy delivered during the HLH from eighty-five percent (85%), and multiplying the result by 3,300 MWh (one-fifth of 16,500 MWh), which is equal to the quantity of Exchange Energy Pasadena would otherwise deliver for Peaking Capacity made available during such month.

(e) Pasadena shall notify Bonneville and request a reduction in either Pasadena's Exchange Energy obligation or Peaking Replacement Energy obligation, when such reduction is warranted pursuant to this section.

(f) **Order of Precedence**

The Parties shall curtail pro rata on an hourly basis all agreements executed on or before July 1, 1993, for firm energy or capacity, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over agreements executed after July 1, 1993, for

firm energy or capacity. Deliveries pursuant to this Agreement shall have precedence over all nonfirm transactions.

9. POINTS OF DELIVERY

The point of delivery for all deliveries pursuant to this Agreement is NOB, unless otherwise mutually agreed to by the Parties.

10. UNCONTROLLABLE FORCE

(a) **Obligations of the Parties**

Except as provided in section 8, obligations of the Parties shall be excused when failure to perform such obligations is due to an Uncontrollable Force; **provided, however**, that if either Party is unable to perform due to an Uncontrollable Force, such Party shall exercise due diligence to remove such inability in a timely manner. Nothing in this section 10(a) shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(b) **Notice**

Each Party shall notify the other as soon as possible of any Uncontrollable Force which may impair performance under this Agreement. Failure to give notice shall not be deemed a waiver of such Uncontrollable Force.

11. ASSIGNMENT OF AGREEMENT

Neither Party shall have the right to transfer or assign this Agreement or any part hereof without the prior written consent of the other Party. Such consent shall not be unreasonably withheld.

12. NOTICES

(a) Unless this Agreement requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given, or made if delivered in person or sent by telegraph, or by acknowledged delivery, or sent by registered or certified mail, postage prepaid, to the persons specified below:

To Pasadena:

General Manager
City of Pasadena
Water and Power Dept.
150 S. Los Robles Ave., Suite 200
Pasadena, CA 91101

To Bonneville:

Assistant Administrator for Power Sales - P
United States Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

(b) Either Party may, by written notice to the other Party, change the designations or address of the person so specified as the one to receive notices pursuant to this Agreement.

13. DISPUTES

Pending resolution of a disputed matter, the Parties shall continue performance of their respective obligations pursuant to this Agreement. For a period not to exceed 6 months unless otherwise mutually agreed, the Parties shall discuss disputes regarding any matter relating to this Agreement, and shall use their best efforts to amicably and promptly resolve each such dispute. If the Parties have been unable to resolve a disputed matter as specified above, then each Party has the right to adopt any other remedies available under law.

14. GOVERNING LAW

This Agreement shall be interpreted, governed by, and construed under Federal law.

15. WAIVERS

Except as otherwise provided herein or as agreed by the Parties, no provision of this Agreement may be waived except as documented or confirmed in writing. Any waiver at any time by a Party of its right with respect to a default under this Agreement, or with any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter. Either Party may waive any notice or agree to accept a shorter notice than specified in this Agreement. Such waiver of notice or acceptance of shorter notice by a Party at any

time regarding a notice shall not be considered a waiver with respect to any subsequent notice required under this Agreement.

16. SIGNATURE CLAUSE

`Each Party hereto represents that it has the authority to execute this Agreement and that it has been duly authorized to enter into this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By **/S/ WALTER E. POLLOCK**
Assistant Administrator
for Power Sales

Name **Walter E. Pollock**
(*Print/Type*)

Date **June 29, 1994**

CITY OF PASADENA, CALIFORNIA

By **/S/ EDMUND F. SOTELO**

Name **Edmund F. Sotelo**
(*Print/Type*)

Title **Interim General Manager**
Water and Power development

Date **6/9/94**

(PMLAN-PMC-W:\PMC\CT\93658\93658.DOC)

Dated: **6/22/94**

Attest: **/S/ VIVIAN LEE STEWART**

APPROVED AS TO FORM
This 1 day Of June, 1994
By N Rasmussen
Assistant General Counsel

Service Agreement No. 00TX-10286

AUTHENTICATED

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
CORAL POWER L. L. C

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Exhibit (Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit B (Facilities Charges)
Exhibit C (Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 2nd day of February , 2000 by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and Coral Power L. L. C. (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 TERMS AND CONDITIONS

BPA agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Services (PTP Transmission Service) in accordance with the provisions of this Service Agreement and the Open Access Transmission Tariff (Tariff). The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference. BPA may change the terms and conditions of

the Tariff upon, and only upon, a determination by the Federal Energy Regulatory Commission (Commission) that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 STATEMENT OF SPECIFICATION FOR LONG-TERM FIRM TRANSMISSION SERVICE

The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit A and made applicable to that transaction.

1.3 WHOLESALE POWER AND TRANSMISSION RATES SCHEDULES

BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated by this reference.

1.4 FACILITIES CHARGES

All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit B.

1.5 ANCILLARY SERVICES

The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit C.

1.6 TRANSMISSION SCHEDULING PROVISIONS

The Transmission Customer shall schedule transmission transactions in accordance with BPA's Transmission Scheduling Provisions and Procedures as posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPAT

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 2400 hours on December 31, 1999. Service under this Service Agreement shall terminate at 2400 hours on December 31, 2004. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 CHARGES FOR TRANSMISSION SERVICE
The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the BPA Wholesale Power and Transmission Rate Schedules.

4.2 BILLING AND PAYMENT
Bills for all services provided under this Service Agreement shall be payable in accordance with the Tariff.

4.3 BPA APPROPRIATIONS REFINANCING ACT, PUBLIC LAW 104-134
The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT
Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If to Coral Power, L. L. C

Coral Power L. L. C
909 Fannin, Suite 700
Houston, TX 77010
Attention: Ms. Diane Davis
Senior Contract Administrator
Phone: (713) 767-5313
Fax: (713) 265-5313

If to BPA

Bonneville Power Administration
P. O. Box 491
Vancouver, WA 98666-0491
Attention:
Transmission Account Executive for:
Coral Power, L. L. C
Phone: (360) 418-8285
Fax: (360) 418-8320

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified transmission service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within forty-five (45) days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 INTERCONNECTION WITH OTHER SYSTEMS

Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 GOVERNING LAW

This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3. AMENDMENTS

Except as provided in Articles 1.1, 6.4 and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 TARIFF REVISIONS

In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than sixty (60) days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within thirty (30) days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then

approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within thirty (30) days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the transmission service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.4 REVISION OF EXHIBITS

If any changes to Exhibits A, B, or C are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.4.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit A pursuant to this Service Agreement, BPA shall prepare a revised Exhibit A. BPA reserves the unilateral right to amend contiguous point of delivery provisions in Exhibit A of this Service Agreement.

6.4.2 If the Parties agree to change Exhibit B, BPA shall prepare a new Exhibit B. BPA reserves the right to revise Exhibit B annually to reflect changes consistent with the provisions of Exhibit B, section 1.

6.4.3 If the Parties agree to change Exhibit C, BPA shall prepare a new Exhibit C. BPA reserves the right to update the loss factors identified in Exhibit C, section 2, Transmission Loss Factors.

6.5 TEMPORARY LOAD SHIFTS AND MAINTENANCE NOTIFICATION

The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within four (4) days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The point of contact for each Party will be designated pursuant to Article 5.2 of this

Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within four (4) days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.6 SEVERABILITY

In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.7 COMPUTATION OF TIME

To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.8 NO THIRD PARTY BENEFICIARIES

This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.9 WAIVERS

Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.10 SUCCESSORS AND ASSIGNS

This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.11 SERVICE AGREEMENT GOVERNS

In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.12 ENTIRE AGREEMENT

This Service Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

ARTICLE 7
SIGNATURES

The signatories represent that they are authorized to enter into this Service Agreement on behalf of the Party for who they sign.

CORAL POWER, L. L. C		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	**/S/ Jeffrey F. Beicker**	By:	**/S/ S. J. Long**
Name: *(Print/Type)*	**Jeffrey F. Beicker**	Name: *(Print/Type)*	Sally J. Long
Title:	**Vice President**	Title:	Transmission Account Executive
Date:	**02/09/2000**	Date:	**12-21-1999**

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EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR
LONG-TERM FIRM TRANSMISSION SERVICE

Long-Term service has not been requested at this time under this Service Agreement

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EXHIBIT B
FACILITIES CHARGES

Facilities Charges are not required at this time for service under this Service Agreement.

EXHIBIT C
ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL [1])	00TX-10286
(b)	**Energy Imbalance**	N/A	
(c)	**Control Area Reserves for Resources**	N/A	
(d)	**Control Area Reserves for Interruptible Purchases**	N/A	
(e)	**Load Regulation**	N/A	
(f)	**Reactive Supply and Voltage Control**	BPA(TBL)	00TX-10286
(g)	**Transmission Losses**	BPA(TBL)	00TX-10286

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) **Transmission Losses Associated with Federal Power**
Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) **Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power**
The Transmission Customer shall compensate BPA for losses BPA incurs when providing transmission service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be determined by multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in section 2; and

[1] BPA's Transmission Business Line.

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) Transmission Losses Associated with Delivery Facilities
Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year [2], pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) Notification

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer shall choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice for compensating BPA for transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission

[2] Fiscal Year is defined as the twelve-month period from October 1 through September 30.

Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit C.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate in the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) **Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year** The Transmission Customer has elected to purchase Transmission Losses, pursuant to the APS-96 rate schedule, at a rate of 22.80 mills per kWh for the period 2400 hours December 31, 1999, through 2400 hours September 30, 2000.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit C as appropriate, but not more frequently than once in a twelve-month (12) period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit C incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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AUTHENTICATED

Amendment No. 1
Agreement No. 00TX-10286

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

CORAL POWER, L.L.C.

This AMENDMENT to the Point-to-Point Transmission Agreement, Contract Number 00TX-10286 (Agreement), is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Transmission Provider) and Coral Power, L.L.C. (Transmission Customer). The Transmission Provider and the Transmission Customer are sometimes referred to individually as "Party", and collectively as "Parties," as the context suggests below.

This Amendment to the Agreement between the Transmission Provider and the Transmission Customer acknowledges the Parties' desire to extend the term of the Service Agreement to 0000 hours on January 1, 2010. The Parties agree that all other terms and conditions of the Agreement, as amended, remain the same.

The Transmission Provider and the Transmission Customer agree:

1. **EFFECTIVE DATE**
   This Amendment shall take effect on the date executed by the Parties (Effective Date).

2. **AMENDMENT OF AGREEMENT**

   The Transmission Provider and the Transmission Customer wish to amend the Agreement by deleting Article 3, Term of Service Agreement, and Article 5, NOTICES, and replacing them with the following:

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 0000 hours on the Effective Date and terminate at 0000 hours on January 1, 2010. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 5.2 below), shall be in writing and shall be deemed to have been received if delivered in person, by First Class mail, by telefax or sent by acknowledged delivery.

If to the Transmission Customer:

Coral Power, L.L.C.
909 Fannin, Suite 700
Houston, TX 77010
Attention: Ms. Diane Davis
Title: Senior Contract Administrator
Phone: (713) 767-5313
Fax: (713) 265-5313

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409
Attention: Transmission Account Executive for Coral Power, L.L.C.– TM/OPP2
Phone: (360) 619-6011
Fax: (360) 619-6940

By Overnight Delivery

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409
Attention: Transmission Account Executive for Coral Power, L.L.C.– TM/OPP2
Phone: (360) 619-6011
Fax: (360) 619-6940

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by telefax or sent by First Class mail or acknowledged delivery.

If to the Transmission Customer:

Coral Power, L.L.C.
4445 Eastgate Mall, Suite 100
San Diego, CA 92121
Attention: Wayne Young
Title: Trader
Phone: Real-Time (858) 320-1500
Fax: (858) 320-1550

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491
Attention: Real-Time Scheduling
Phone: **EMERGENCY ONLY**
(360) 695-2650
Fax: (360) 418-8740

3. **SCHEDULING AGENT**
None.

4. **SIGNATURES**
The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

CORAL POWER, L.L.C.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ BETH BOWMAN**	By: **/S/ ALLAN F. PASCHKE**
Name: **Beth Bowman** *(Print/Type)*	Name: Allan F. Paschke *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **October 11, 2004**	Date: **10/4/04**

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Exhibit A adds transmission service under Table 3.

TABLE 3
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1349232

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2010.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
Coral Power, LLC	Big Eddy Substation 500 kV	BPA	50,000	Nevada-Oregon Border (NOB) 1000 kV	LADWP	50,000	Various [1]
Total Maximum Reserved Capacity			**50,000**			**50,000**	

3. POINT OF RECEIPT

Big Eddy Substation

Location: the point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

[1] Various Receiving Parties – Special Intertie Service.

4. **POINT OF DELIVERY**

Nevada – Oregon Border (NOB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where Bonneville shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
None.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

7. **SERVICE AGREEMENT CHARGES**
Service under this Agreement will be subject to some combination of the charges detailed in this Table 3 and in exhibits B and C. The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff, as amended, and the applicable TBL Transmission and Ancillary Service Rate Schedules, as amended.

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
System Impact and/or Facilities Study Charges are not required at this time for service under this Service Agreement.

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT

None.

9. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

CORAL POWER, L.L.C.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ BETH BOWMAN**	By: **/S/ ALLAN F PASCHKE**
Name: **Beth Bowman** *(Print/Type)*	Name: Allan F. Paschke *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **October 11, 2004**	Date: **10/4/04**

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Exhibit A adds transmission service under Table 4.

TABLE 4
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1349240

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2010.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
Coral Power, LLC	Big Eddy Substation 500 kV	BPA	50,000	Nevada-Oregon Border (NOB) 1000 kV	LADWP	50,000	Various [1]
Total Maximum Reserved Capacity			**50,000**			**50,000**	

3. POINT OF RECEIPT

Big Eddy Substation

Location: the point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

[1] Various Receiving Parties - Special Intertie Service.

4. POINT OF DELIVERY

Nevada – Oregon Border (NOB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where Bonneville shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

5. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION

None.

6. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

7. SERVICE AGREEMENT CHARGES

Service under this Agreement will be subject to some combination of the charges detailed in this Table 4 and in exhibits B and C. The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff, as amended, and the applicable TBL Transmission and Ancillary Service Rate Schedules, as amended.

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
System Impact and/or Facilities Study Charges are not required at this time for service under this Service Agreement.

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT
None.

9. SIGNATURES
The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

CORAL POWER, L.L.C.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ BETH BOWMAN**	By: **/S/ ALLAN F PASCHKE**
Name: **Beth Bowman** *(Print/Type)*	Name: Allan F. Paschke *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **October 11, 2004**	Date: **10/4/04**

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Dated 3/12/97
Service Agreement No. 97TX-10031

AUTHENTICATED

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
MORGAN STANLEY CAPITAL GROUP INC.

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Exhibit A (Point-to-Point Service Transmission (Tariff))
Exhibit B (Application for Point-to-Point Transmission Service)
Exhibit C (Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit D (System Impact Study Agreement)
Exhibit E (Facility Study Agreement)
Exhibit F (Transmission Scheduling Provisions)
Exhibit G (Confirmation Request for Short-Term PTP)
Exhibit H (Wholesale Power and Transmission Rate Schedules)
Exhibit I (Facilities Charges)
Exhibit J (Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 21st day of March 1997, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and Morgan Stanley Capital Group Inc.(hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

W I T N E S S E T H :

WHEREAS BPA provides Transmission Service under BPA's Point-to-Point (PTP) Tariff; and

WHEREAS the Transmission Customer desires to receive Transmission Service under the PTP Tariff;

NOW, THEREFORE, in consideration of the promises and mutual covenants and agreements herein contained, the Parties do agree as follows:

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 Terms and Conditions. The terms and conditions under which the PTP Transmission Service is offered and accepted are pursuant to this Service Agreement and to the PTP Transmission Service Tariff. The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference and made a part of this Service Agreement as Exhibit "A." Unless otherwise mutually agreed in writing by the Parties, BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Federal Energy Regulatory Commission (FERC) that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 Application. The Application for PTP Transmission Service requested by the Transmission Customer and accepted by BPA for this Service Agreement is hereby

incorporated by this reference and made a part of this Service Agreement as Exhibit "B."

1.3 **Statement of Specifications for Long-Term Firm Transmission Service.** The Statement of Specifications (including Ancillary Services) for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer and accepted by BPA are hereby incorporated by reference and made a part of this Service Agreement as Exhibit "C."

1.4 **System Impact/Facilities Study.** Study Agreements for a System Impact Study and/or a Facilities Study, if performed for this Application, are hereby incorporated by this reference and made a part of this Service Agreement as Exhibits "D" and "E," respectively.

1.5 **Transmission Scheduling Provisions.** The Transmission Scheduling Provisions are hereby incorporated by reference and made a part of this Service Agreement as Exhibit "F." All transactions which must be scheduled under this Service Agreement shall be scheduled in accordance with the scheduling provisions in Section 2.7(d) of the Tariff and Exhibit F of this Service Agreement.

1.6 **Reservation Confirmation for Short-Term PTP.** The Confirmation Request for Short-Term PTP is hereby incorporated by reference and made part of this Service Agreement as Exhibit "G." The service specifications for Short-Term Firm and Nonfirm transmission service under this Service Agreement shall be as provided in Exhibit G.

1.7 **BPA Wholesale Power and Transmission Rates Schedules.** The BPA Wholesale Power and Transmission Rates Schedules are hereby incorporated by reference and made part of this Service Agreement as Exhibit "H."

1.8 **Facilities Charges.** All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated by reference and made a part of this Service Agreement as Exhibit "I."

1.9 **Ancillary Services.** The Ancillary Services for PTP Transmission Service under this Service Agreement requested by the Transmission Customer and accepted by BPA are hereby incorporated by this reference and made a part of this Service Agreement as Exhibit "J." Each of the Ancillary Services applicable to all executed short-term reservation confirmation requests shall be specified in Exhibit G.

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence on 2400 hours on March 31, 1997, and shall terminate on 2400 hours on September 30, 2001, unless terminated earlier pursuant to Section 9.9 of the Tariff. All obligations and liabilities incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 **Charges for Transmission Service.** The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the rate schedules as specified below.

4.1.1 All applicable charges pursuant to the PTP Transmission Rate as specified in Exhibit H (PTP-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.2 All applicable charges pursuant to the Ancillary Products and Services Rate for such services as specified in Exhibit G and Exhibit J (APS-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.3 Reserved Nonfirm Transmission Rate as specified in Exhibit G ((RNF-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.4 Energy Transmission Rate as specified in Exhibit H (ET-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.5 Advance Funding Rate for facilities listed in Exhibit I (AF-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.6 Use-of-Facilities Rate for facilities listed in Exhibit I (UFT-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.1.7 Southern Intertie Rate as specified in Exhibit C and Exhibit G (IS-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules).

4.1.8 Montana Intertie Rate as specified in Exhibit C and Exhibit G (IM-96, or its successor as revised) and listed in the Wholesale Power and Transmission Rate Schedules.

4.2 **Billing and Payment.** Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and all such bills shall be due and payable in accordance with Section 20 of the Tariff.

4.3 **Commitment to Five-Year Rate.** The Transmission Customer agrees that prior to October 1, 2001, it hereby waives its rights to: (a) decrease such amount (in megawatts (MW)) of Long-Term Firm Transmission Demand, as set forth in Exhibit C; and (b) terminate service pursuant to Section 9.9 of the Tariff. BPA

agrees that such amounts constitute a firm commitment of transmission demand through September 30, 2001. BPA will charge the Transmission Customer for such initial MW of Long-Term Firm Transmission Demand amount at the rates established for such service pursuant to the PTP-96, IS-96, or IM-96 rate schedules, and the Transmission Customer agrees to pay such rates, pursuant to and consistent with, the Transmission Settlement Agreement, as adopted in Administrator's Record of Decision adopting the 1996 Final Rate Proposal (Document No. WP-96-A-02, part 2 of 2, Attachment 1), dated April 4, 1996. The Transmission Customer's right to dispute any rate increase proposed by BPA prior to October 1, 2001, shall be pursuant to the Transmission Settlement Agreement as cited above.

4.4 **Load Reduction Due to Changes in Federal or State Law.** The Transmission Customer shall provide written notice to BPA as soon as practicable in the event that a retail consumer of the Transmission Customer obtains access to a power supplier other than the Transmission Customer because a regulatory, legislative, or judicial body of competent jurisdiction, not including any governing body, commission, or board of the Transmission Customer, has required that the Transmission Customer provide such access through the use of the Transmission Customer's transmission and/or distribution facilities, and the Transmission Customer thereby suffers a reduction in retail load. At a mutually agreeable time thereafter, BPA and the Transmission Customer shall initiate discussions to determine whether a change in the Transmission Customer's Network Load pursuant to Exhibit C, Network Load, is appropriate and, if so, the mitigation, if any, to which BPA is entitled.

4.5 BPA Appropriations Refinancing Act, Public Law 104-134

Consistent with Section 3201(i) of Public Law No. 104-134:

4.5.1 BPA shall establish rates and charges on the basis that:

4.5.1.1 the principal amount of an old capital investment shall be no greater than the new principal amount established under Section 3201(b) of Public Law 104-134;

4.5.1.2 the interest rate applicable to the unpaid balance of the new principal amount of an old capital investment shall be no greater than the interest rate established under Section 3201(c) of Public Law 104-134;

4.5.1.3 any payment of principal of an old capital investment shall reduce the outstanding principal balance of the old capital investment in the amount of the payment at the time the payment is tendered; and

4.5.1.4 any payment of interest on the unpaid balance of the new principal amount of an old capital investment shall be a credit against the appropriate interest account in the amount of the payment at the time the payment is tendered.

4.5.2 apart from charges necessary to repay the new principal amount of an old capital investment as established under Section 3201(b) of Public Law 104-134 and to pay the interest on the principal amount under Section 3201(c) of Public Law 104-134, no amount may be charged for return to the U.S. Treasury as repayment for or return on an old capital investment, whether by way of rate, rent, lease payment, assessment, user charge, or any other fee;

4.5.3 amounts provided under Section 1304 of Title 31, U.S. Code, shall be available to pay, and shall be the sole source for payment of, a judgment against or settlement by BPA or the United States on a claim for a breach of this section; and

4.5.4 the contract provisions specified in this section do not:

4.5.4.1 preclude BPA from recovering, through rates or other means, any tax that is generally imposed on electric utilities in the United States, or

4.5.4.2 affect BPA's authority under applicable law, including Section 7(g) of the Pacific Northwest Electric Power Planning and Conservation Act, to:

4.5.4.2.1 allocate costs and benefits, including but not limited to fish and wildlife costs, to rates or resources, or

4.5.4.2.2 design rates.

4.5.5 Terms used in this section shall have the same meaning as they have under Section 3201(b) of Public Law 104-134.

4.5.6 References in this section to Section 3201 of Public Law 104-134 are to that section as approved by the 104th Congress and signed by the President in April of 1996.

(e) Terms used in this section shall have the same meaning as they have under Section 3201(b) of Public Law 104-134.

(f) References in this section to Section 3201 of Public Law 104-134 are to that Section as approved by the 104th Congress and signed by the President in April of 1996.

ARTICLE 5
NOTICES

5.1 **Notices Relating to Provisions of Service Agreement.** Any notice, request, demand, or statement which may be given to or be made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in paragraph 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If the notice is to the Transmission Customer:

Morgan Stanley Capital Group Inc.
Commodities Department, Fourth Floor
1585 Broadway
New York, NY 10036
Attn: Mr. Simon Greensheilds, Vice President

If the notice is to BPA:

Senior Account Executive for Morgan Stanley Capital Group Inc.
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

5.2 **Notices of An Operating Nature.** Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified transmission service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should the same not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The point of contact pursuant to this section shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
SYSTEM OPERATIONS

The Transmission Customer having Point(s) of Interconnection and Points of Delivery with the Federal Columbia River Transmission System (FCRTS) shall be required to designate a Control Area and to comply with the System Operation and Interconnection Requirements in Section 7.4 of the Tariff prior to commencement of Transmission Service hereunder. Point of Interconnection and Points of Delivery not on the Transmission Customer's system shall be governed by agreements between BPA and those interconnected parties.

ARTICLE 7
SPECIFICATIONS FOR ANCILLARY SERVICES

Ancillary Services provided by BPA under this Service Agreement shall be provided in accordance with Section 8 of the Tariff and billed in accordance with Section 20 of the Tariff. The Ancillary Services provided to the Transmission Customer shall be specified in

all executed reservation confirmations in Exhibit G and in the Ancillary Services Exhibit J of this Service Agreement.

ARTICLE 8
MISCELLANEOUS

8.1 **Interconnection With Other Systems.** Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

8.2 **Governing Law.** This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

8.3 **Amendments.** Except as provided in Article 1.1 and Article 8.4, and unless otherwise mutually agreed in writing by the Parties, BPA may change this Service Agreement upon, and only upon, a determination by the Commission that such change is just, reasonable and not unduly discriminatory or preferential. Otherwise, this Service Agreement may be amended only upon mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

8.4 **Revision of Exhibits.** If any changes to Exhibits C, D, E, F, G, H, I, or J are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such nonrate changes.

8.4.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties mutually agree to change Exhibit C pursuant to this Service Agreement, BPA shall prepare and issue a revised Exhibit C. BPA reserves the unilateral right to amend contiguous Point of Delivery provisions in Exhibit C, footnote no. 2, of this Service Agreement.

8.4.2 If the Parties mutually agree to perform study agreements for a System Impact Study and/or Facilities Study under this Service Agreement, BPA shall prepare a revised Exhibit D and/or Exhibit E incorporating such studies.

8.4.3 For changes to any of the provisions contained in the Transmission Scheduling Provisions Exhibit (Exhibit F) to reflect current practice, BPA shall prepare a new Exhibit F.

8.4.4 For changes to the Reservation Confirmation for Short-Term PTP (Exhibit G) to reflect current practice, BPA shall prepare a new Exhibit G.

8.4.5 Except as provided in paragraph 4.3, BPA may change rates pursuant to applicable law and procedures. BPA shall prepare a new Exhibit H incorporating such changes.

8.4.6 BPA reserves the right to revise Exhibit I annually to reflect changes in: (a) the yearly noncoincidental demands on the facility under this Service Agreement and other agreements; (b) changes in interest and amortization (I&A) annual cost ratio; and (c) changes in operation and maintenance (O&M) annual cost.

8.4.7 If the Parties mutually agree to change Exhibit J, section 1, pursuant to this Service Agreement, BPA shall prepare and issue a revised Exhibit J. BPA reserves the right to update loss methodology consistent with Exhibit J, section 2 to incorporate values which represent current FCRTS operating conditions or to incorporate any value, used in the exhibit to calculate the losses, which has changed due to a change in methodology.

8.5 Conversion to Any Tariffs Offered by BPA. Upon mutual agreement of the Parties, the notice periods for terminating this Service Agreement and for commencing service under another tariff offered by BPA may be shortened.

8.6 Severability. In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by FERC or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

8.7 **Computation of Time.** On computing any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of this period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next business day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

8.8 **No Third Party Beneficiaries.** This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto expressly do not intend to create any obligation or promise of performance to any other third person or entity nor have the Parties conferred any right or remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns to enforce this Service Agreement.

8.9 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

8.10 **Successors and Assigns.** This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

8.11 **Service Agreement Governs.** In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

8.12 **Entire Agreement.** Except as stated otherwise herein, this Service Agreement constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect thereof.

IN WITNESS WHEREOF, the duly authorized representatives of BPA and the Transmission Customer have executed this Service Agreement as of the date first above written.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ TIM CASTILLE
Senior Account Executive

Name Timothy P. Castille
(Print/Type)

Date 3-13-97

MORGAN STANLEY CAPITAL GROUP INC.

By /S/ SIMON GREENSHIELDS

Name **Simon Greenshields**
(Print/Type)

Title **Vice President**

Date **March 20 97**

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

1. TERM OF TRANSACTION

Start Date: , at 2400 hours.
Termination Date: The earlier of: (a) 2400 hours on _____; or (b) 2400 hours on the termination date established pursuant to Article 3 of this Service Agreement.

2. DELIVERING PARTY/RESOURCE

3. RECEIVING PARTY

4. CONTROL AREA

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point of Interconnection (Voltage)	Transmission Demand (MW)	Point of Delivery (Voltage)	Transmission Demand (MW)
Substation kV		Substation kV	
Maximum Transmission Demand	1/		1/ 2/

[Note: Does Maximum Transmission Demand cover losses?]

[Use footnote 1 if a Short-Distance Discount applies]_____

1/ The Short-Distance Discount (SDD) is applied to the Transmission Customer's monthly Transmission Demand for the purpose of computing the monthly bill. Reference Exhibit C, Section 10, for the SDD transmission demand.

[Use footnote 2 if contiguous Points of Delivery applies]_____

2/ The Transmission Customer's designated contiguous Points of Delivery are subject to the following terms.

(a) All Points of Delivery on the delivery side must be interconnected through a transmission or distribution system, and operated normally closed. The Points of Delivery must be significantly interconnected electrically on both high side and low side.

(b) In the event of a credible outage, each Point of Delivery within the contiguous set must be capable of providing electric backup service to any other Point of Delivery of that contiguous set so that retail customers within the load center served by the contiguous set of Points of Delivery realize no interruption in service.

(c) All Points of Delivery in the set of contiguous Points of Delivery must be located on the same side of a constraint or potential constraint. Shifts in loads from one Point of Delivery to another Point of Delivery in the contiguous set may not adversely affect any constraint, such as those posted on BPA's Open Access Same-Time Information System (OASIS).

(d) The Transmission Customer may not direct BPA to deliver a specific amount of demand to a specific Point of Delivery within the contiguous set of Points of Delivery. BPA has no obligation to deliver specific amounts to the delivery points which constitute the contiguous set of Points of Delivery. BPA has no obligation to construct new facilities at or between Points of Delivery included in the contiguous set of Points of Delivery as long as BPA can deliver the combined demand to the contiguous set of Points of Delivery.

(e) All Points of Delivery within the contiguous set of Points of Delivery must be in a single control area; all power associated with the contiguous set of Points of Delivery must be scheduled.

(f) All Points of Delivery associated with the Southern Intertie are specifically excluded from consideration as part of a contiguous set of Points of Delivery. Big Eddy, John Day, California/Oregon Border (COB), and Nevada/Oregon Border (NOB) are independent Points of Delivery.

(g) The utility requesting contiguous Points of Delivery must be capable of receiving electric service at each of the Points of Delivery in the contiguous set. If the utility is requesting contiguous Points of Delivery in order to deliver to a third party, then that third party must be capable of receiving delivery at each of the Points of Delivery in the contiguous set.

(h) Where appropriate, the Transmission Customer must agree to use limits on the individual Points of Delivery included in the contiguous set of Points of Delivery.

(i) Contiguous Points of Delivery are granted for real power only. Issues associated with reactor power shall be covered by separate procedures.

(j) These criteria shall be reviewed annually. An individual customer's situation shall be reviewed if there are any changes in how its system is served or impacted by any transmission system conditions. BPA reserves the right to modify any characteristics of a customer's contiguous Point of Delivery if changes in a system warrant such modification.

(k) The Transmission Customer is entitled to receive 90 days written notice from BPA of changes to the contiguous Point of Delivery provisions listed in this footnote.

6. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) **Substation**

Location:

Voltage: kV

Transmission Demand: MW

Metering:

Delivering Party/Resource:

Control Area:

7. DESCRIPTION OF POINTS OF DELIVERY

(a) **Point of Delivery**

Name of Point of Delivery

Location:

Voltage:

Metering:

Loss Adjustment. If applicable, BPA will adjust for transmission losses between the Transmission Customer's point of delivery and point of metering. Such adjustments shall be specified in written correspondence between BPA and the Transmission Customer.

Exceptions. [If none, delete the following sub-items]

(1) **Period of Service**
(Applicable when the Point of Delivery is not yet in service or is scheduled to be removed.)

(2) **Future Voltage**
(Applicable when the voltage is scheduled to be changed.)

(3) **Demand Limits**

(4) **Phase**
(Applicable when BPA is delivering single phase, not 3-phase power.)

(5) **Service Over Other Facilities**
(Applicable when BPA uses the Transmission Customer's own facilities or a third party's facilities to serve the Transmission Customer's.)

(6) **Default Methodology for Calculating Hourly Amounts of Transmission Customer's Generation**
(Applicable when the existing meters only measure monthly amounts.)
In some cases, the resource will be treated as an offset to the Transmission Customer's load. Consumer resources are not subject to this requirement.

(7) **Calculation Methods For Determining How Meter Readings Are To Be Added or Subtracted to Calculate the Billing Amounts**

(8) **Multiplier To Be Used To Calculate Demand From Average Energy Deliveries in Points of Delivery Without Demand Recording Devices**

(b) **Point(s) of Delivery Served by Transfer [Include only if it applies]**
The Transmission Customer, its Agent, or its power supplier is responsible for arrangements required to transmit power over the facilities of the Intervening System described in this section to Points of Delivery contained herein. To the extent the Transmission Customer is reliant upon agreements between BPA and the Intervening System owner for such arrangements, or if BPA has otherwise arranged to provide financial assistance to the Transmission Customer to secure such transmission service to the Points of Delivery from the Intervening System owner, service to the Transfer Points of Delivery are subject to the PTP-96 rate schedule, or its successor.

Transmission Service under this Service Agreement shall encompass all Integrated Network Transmission System facilities, as defined by the Tariff, necessary to serve the Transmission Customer's Network Load.

Name of Transfer Point [*list Point of Replacement here]*

Location

Voltage

BPA's Point of Receipt from Intervening System *[include only if applicable]*

Transmission Customer Point of Receipt and Point of Metering. [*list the locations where the Transmission Customer takes final receipt of power from the transferor. If the Point of Metering is different than the Point of Receipt, list Point of Metering under a separate heading]*

Loss Adjustment. If applicable, BPA will adjust for transmission losses between the Transmission Customer's point of receipt and point of metering. Such adjustments shall be specified in written correspondence between BPA and the Transmission Customer.

Exception

8. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

9. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE [Only include if using transfer, if yes, include name of transfer agent]**

10. **SHORT DISTANCE DISCOUNT**
[0.6 + (0.4 x transmission distance/75)]

Points of Delivery	Circuit Miles from (Name POI)	Adjusted SDD POI Demand (kW) */	Adjusted SDD POD Demand (kW) */
Substation			
Substation			

*/ The SDD is not available for transmission service to secondary points of interconnection or delivery.

SYSTEM IMPACT STUDY AGREEMENT

A System Impact Study is not required at this time for the service under this Service Agreement.

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FACILITY STUDY AGREEMENT

A Facility Study is not required at this time for the service under this Service Agreement.

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TRANSMISSION SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

The purpose of this exhibit is to describe how the Parties will effect transmission transactions under this Service Agreement.

2. EXHIBIT PROVISIONS

(a) **Scheduling Principles**

The procedures in this exhibit are intended to achieve the following principles:

(1) promote efficient system operations; and

(2) provide workable scheduling procedures for the timely delivery of power.

(b) **Control Area Requirements**

(1) In order to schedule power, a Transmission Customer must designate a Host Control Area (HCA) as defined by North American Electric Reliability Council (NERC) to implement its schedules. The HCA may be the sending Control Area, the receiving Control Area, or an intermediary Control Area.

(2) BPA shall be the HCA for any transaction involving either:

(A) generation located within BPA's Control Area; or

(B) service to a load within BPA's Control Area.

(3) If BPA is the intermediary Control Area in a single transaction or set of transactions, the Transmission Customer may designate a HCA other than BPA. The Transmission Customer must inform BPA of its choice no later than the time of preschedule. BPA has no obligation to accept schedules from any HCA that does not agree to abide by the scheduling requirements set forth in this exhibit.

(4) If the Transmission Customer has designated a HCA for a single schedule, it must remain the HCA for the entire duration of the schedule. In the event the Transmission Customer fails to identify a HCA for its next schedule, BPA will assume that the designated HCA is the same entity as designated for the Transmission Customer's last schedule. Any designation changes shall be made pursuant to Article 5.1 of this Service Agreement.

(5) The Transmission Customer may arrange interchange schedules; however, the HCA shall confirm and then implement the interchange schedule. The HCA is responsible to the Western Systems Coordinating Council and NERC for the interchange scheduling arrangements of the Transmission Customer, including the responsibility for resolving any inadvertent energy accumulation that may result from the Transmission Customer's incorrect or uncoordinated scheduling of the interchange.

(6) Any Transmission Customer for whom BPA is the HCA must schedule transmission to or from BPA's Control Area, i.e., the Transmission Customer's Scheduling Agent is BPA for purposes of scheduling transmission under this exhibit.

(7) Any Transmission Customer or its Scheduling Agent using a HCA other than BPA must establish and verify schedules with other Control Areas through the HCA, but the HCA is responsible for implementing and assuring the accuracy of the schedule.

(c) **Coordinating Requirements**

(1) All schedules must be provided to BPA on Workdays (defined as any day *both* Parties consider a workday).

(2) Schedules apply to the following day or days (if the following day or days are not Workdays).

(3) Scheduled hourly values are to be referenced by the "hour ending" time on the 24-hour clock (i.e., the schedule for 2-3 p.m. is referred as the "hour ending 15").

(4) Unless otherwise agreed, all schedules will be effectuated on an hourly basis using the standard 20-minute ramp period centered on the hour (i.e., beginning 10 minutes prior to the hour and ending 10 minutes after the hour).

(5) All schedules with BPA are to be stated in Pacific Time (PT) and are to begin with the hour ending 1.

(6) The Transmission Customer or its Scheduling Agent agrees to submit all hourly prescheduled quantities in whole megawatthour amounts.

(d) **Prescheduling Requirements**
Prescheduling is the process of establishing hourly schedules through the following Workday(s).

(1) **Preschedule Submissions**

(A) The Transmission Customer or its Scheduling Agent agrees to submit schedule(s) covering all transactions into, out of, or within BPA's Control Area.

(B) BPA may require Transmission Customers or its Scheduling Agent to submit *estimated* preschedules prior to the final preschedule.

(C) The Transmission Customer or its Scheduling Agent agrees to submit a *final* hour*ly* preschedule for the next day or days by 1000 of each Workday.

(E) The maximum number of preschedule days is 4 days, except that by mutual agreement BPA may accept preschedules for up to 5 or 6 days as needed to accommodate a Transmission Customer's special scheduling requirements for contiguous weekend-holiday periods. (For example, BPA will accept schedules for the period Thanksgiving Thursday through Monday if the Transmission Customer observes the Friday after Thanksgiving as a holiday.)

(2) **Information Required to Be Included in Preschedule**
Any schedule submitted to BPA by the Transmission Customer or its Scheduling Agent must include, at a minimum, the following information:

(A) the HCA;

(B) the supplier, receiver, and wheeling entities involved in the transaction;

(C) the MW amount of the schedule;

(D) the starting and ending times for each schedule;

(E) the transmission service being scheduled; and

(F) the point of receipt/delivery for the transaction.

(e) **Changes from Preschedule**

(1) The Transmission Customer or its Scheduling Agent may not change the hourly amounts of its preschedules except by mutual agreement with BPA. The Transmission Customer's generation that provides automatic generation control is exempt from this requirement.

(2) To the extent changes from the preschedule become necessary, the Transmission Customer or its Scheduling Agent must submit such requests no later than 30 minutes prior to the scheduled hour for which the change becomes effective.

(3) Multihour changes from preschedule shall specify an "hour beginning" and an "hour ending" and shall never be stated as "until further notice."

(4) Upon a Transmission Customer's or its Scheduling Agent's request, BPA will consider mid-hour changes from preschedule under critical operating conditions such as loss of a resource or transmission path. The Transmission Customer or its Scheduling Agent and BPA must agree to the effective time, ramp duration, integrated, and revised net

schedules for mid-hour changes. Mid-hour schedule changes shall not be made for economic or load shaping purposes. Such changes are subject to applicable charges.

(f) **Wheeling Requirements**

(1) **Scheduling Requirements for Wheeled Power**
The Transmission Customer's Scheduling Agent and HCA must ensure that any wheeling contract(s) to which they are a party on behalf of the Transmission Customer provide(s) for the following:

(A) The Transmission Customer or its Scheduling Agent must arrange schedules with affected wheeling entities to or from the agreed-upon point of receipt/delivery.

(B) If BPA provides wheeling service, including those for which BPA is the HCA, the Transmission Customer or its Scheduling Agent must notify BPA of changes to wheeling arrangements no later than 30 minutes prior to the scheduled hour for which the wheeled energy transaction becomes effective.

(C) The Transmission Customer or its Scheduling Agent must acquire Transmission consistent with BPA's Transmission Reservation and Scheduling Procedures and the PTP and NT Tariffs.

(g) **Emergency Requirements**

(1) **Loss of Transmission Path**

(A) The path operator shall notify affected Transmission Customers, their Scheduling Agent and HCA as rapidly as possible of the loss of a transmission path.

(B) The path operator will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify schedules, as required, per the established effective time, and agree on integrated and revised net schedules.

(2) **Loss of Generating Resource**
The Transmission Customer agrees to adhere to the following requirements for any resources that it operates and agrees to ensure, through contractual arrangement, that any entity operating a resource on its behalf likewise agrees to the following:

(A) The operating entity (generating entity) will notify BPA and affected Transmission Customers, their Scheduling Agent, and HCA as quickly as possible of the resource loss.

(B) The entity with Control Area responsibility will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify schedules, as required, as of the established effective time, and agree on integrated and revised net schedules.

(3) **General Provisions Regarding Emergencies**
BPA and the Transmission Customer, its Scheduling Agent, and HCA agree to expedite communications to avoid accumulation of inadvertent powerflows or net schedules which place a control burden on other Control Areas.

(h) **After-the-Fact Reconciliation**
The Transmission Customer or its Scheduling Agent agrees to reconcile all schedules and accounts each week with a final reconciliation at the end of each month consistent with the following principles:

(1) The Transmission Customer or its Scheduling Agent and BPA will verify all scheduled transmission.

(2) The Transmission Customer or its Scheduling Agent and BPA will agree on current product balances, loss calculations, and loss schedules, where appropriate.

(3) The Transmission Customer or its Scheduling Agent will assist BPA, as necessary, to reconcile all inadvertent energy in a timely manner.

3. EXHIBIT REVISIONS
The provisions in this Exhibit may be revised by agreement of the Parties.

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Department of Energy

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666

Date: 03/28/97
To: Phone:
Attn: Fax:

RESERVATION CONFIRMATION
Short-Term Point-to-Point

The following memorializes the terms of a transmission transaction agreed to by Bonneville Power Administration Transmission Business Line ("BPA/TBL") and on _____. Transactions hereunder are in accordance with the reference contract listed below.

Reference Contract	97TX- 96XXX	
BPA Confirmation #97TX-	967XX	**Customer Reference No:**
Reservation Desk Contact		()
Customer Contact		**Customer Presched Desk:**
Transmission Seller	BPA Transmission Business Line	()
Transmission Buyer		()
Confirmation Start Date		**Customer Real Time Desk:**
Confirmation End Date		()
Delivery Days of the Week		()
Delivery Hours		
		BPA SW TBL Preschedule No:
Transmission Demand (MW)		**(360) 418-2501**
		BPA NW TBL Preschedule No:
Type of Service (D,W,M)		**(360) 418-2217**
Firm or Nonfirm	Firm or Nonfirm	
Transmission Rate(s)		**BPA Real-time Desk No: Power and Transmission**
Loss Factors		**(360) 418-2189 or 2188**
Loss Return Method		
		Transmission Reservation Desk:
Transmission Price		**(360) 418-8499**
Curtailment Rights		**Fax No. Transmission Scheduling:**
		(360) 418-8208
Point of Interconnection		
POI Control Area		
Delivering Party		
Point of Delivery		
POD Control Area		
Receiving Party		
Scheduling Agent		
Modify LTF/STF?	Yes (See Page 2) or No	

Scheduling: All transmission service transactions will be shown in Pacific Time. Transmission Customer shall preschedule all transactions by 10 a.m., or as mutually agreed, on the day that both Parties observe as a workday preceding the date of transaction. Schedules may only be changed due to uncontrollable forces on either system or by mutual agreement of both Parties. Scheduling and Dispatch are provided by BPA.

Billing: Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and all such bills shall be due and payable in accordance with Section 20 of the Tariff.

Ancillary Services: Applicable Ancillary Services shall be provided by the same provider as listed in Exhibit J if the Transmission Customer also has Long-Term Transmission under this Service Agreement.

Energy Imbalance	[provider]
Control Area Reserves for Resources	[provider]
Control Area Reserves for Interruptible Purchases	[provider]
Load Regulation	[provider]

Other: **List curtailment rights or description of LTF/STF modifications, with secondary POI/PODs and the associated demands.**

This confirmation agreement contains all of the terms and conditions of this transaction and may not be varied or contradicted by any other writing without the express agreement of the BPA Transmission Business Line and the Transmission Customer.

Please copy this fax, sign it, and return it via fax to BPA by 4 p.m. Pacific Time, (Date Reservation Confirmation is sent to Transmission Customer). Additionally, please mail a copy with your original signature to Transmission Supply, noting the routing: TMS.

AGREED AND ACCEPTED

Bonneville Power Administration TBL	**Transmission Customer**
/s/ _____	/s/ _____
Name: _____	Name: _____
Title: _____	Title: _____
Date: _____	Date: _____

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FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

1. USE-OF-FACILITIES COSTS FOR WHICH TRANSMISSION CUSTOMER IS RESPONSIBLE

(a) Calculation of Charges Pursuant to the UFT-96 Rate Schedule.

Facility	Investment 1/	I&A Annual Cost Ratio 2/	I&A Annual Cost	O&M Annual Cost 3/	Sum of Non-Coincidental Demands	$/kW/yr
Substation	$	%	$	$		$
			Total UFT Charge =		$0./kW/mo.	
			kW to apply UFT charge to:		0 kW	

1/ 199X computation.
2/ Based on ACR table dated _____
3/ Based on O&M table dated _____

(b) New Investments In Facilities Serving The Transmission Customer. If new investments are proposed by BPA and agreed to by the Transmission Customer in accordance with the provisions of Sections 11 and 12 of the Tariff, such investments shall be used in the use-of-facilities (UFT) charge under this Service Agreement. Investments of routine or emergency equipment replacements which do not need Transmission Customer approval, shall also be included in the UFT charge under this Service Agreement.

(c) Changes in Costs and Demands. This Exhibit I may be revised annually to reflect changes in: (a) the yearly noncoincidental demands on the facility under this Service Agreement and other agreements; (b) changes in I&A annual cost ratio; and (c) changes in O&M annual cost.

2. DIRECT ASSIGNMENT FACILITIES CHARGES

[List any facilities designated as Direct Assignment Facilities and the Rate]

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ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA(TBL)	
(b)	**Energy Imbalance**	[provider]	
(c)	**Control Area Reserves for Resources**	[provider]	
(d)	**Control Area Reserves for Interruptible Purchases**	[provider]	
(e)	**Load Regulation**	[provider]	

(f) **Transmission Losses.**

[Specify here how the Transmission Customer will handle losses, (i.e., purchase from BPA, return the losses, purchase losses from a third party).]

Compensation for losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) Federal Power Losses: Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96 and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

Transmission loss obligations associated with the delivery of other classes of Federal power shall be established pursuant to the Transmission Customer's contract for the purchase of such power.

(2) FCRTS Losses per the election made pursuant to Section 1(f)(4) below: The Transmission Customer shall provide compensation to BPA for losses incurred when providing transmission service over the FCRTS for amounts of power integrated at Points of Integration, except those amounts associated with purchases specified in 1(f)(1) above, by

multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in Section 2 and

(a) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(b) purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses; or

(c) returning the resulting amount of energy to BPA from either the Transmission Customer's system or from the system of a third party 168 hours after the time of delivery of power for which loss compensation is required, excepting, however, that losses resulting from use of Delivery Facilities, calculated pursuant to 1(f)(3), below, shall be returned on a mutually agreeable basis, but no later than 720 hours after delivery of power for which loss compensation is required.

(3) Delivery Facilities - Delivery Facility losses shall be determined, for each billing cycle, pursuant to the following procedure: (a) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; (b) multiplying the resulting ratio by the total amount delivered to the Transmission Customer less amounts described in 1(f)(1) above; and (c) multiplying the result derived in step 1(f)(3)(b) by the Delivery Facility loss factor listed below in Section 2. Delivery Facility losses are not scheduled for return.

(4) The Transmission Customer shall notify BPA of its method of compensation for losses for all network resources, in writing, 30 days prior to the first day of delivery schedules and 30 days prior to the first day of October each subsequent year during the term of this Service Agreement. In the event the Transmission Customer does not identify their Transmission Losses Compensation Method, in writing, 30 days prior to the first day of delivery schedules and 30 days prior to the first day of October each subsequent year, the default for the Transmission Customer is to purchase losses using the flat rate under

the APS-96 Rate Schedule or its successor. (Period ending September 30, may be less than one year based on start date of Service Agreement.)

Transmission Customer's Method of Compensation of Losses for year one:
The Transmission Customer shall purchase Transmission Losses for the period covering April 1, 1997 - September 30, 1997 at the following rate:

Jan. '97 - March '97	April '97 - June '97	July '97 - Sept. '97
18.55 mills/kWh	11.48 mills/kWh	18.01 mills/kWh

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kilowatthour (kWh) delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA may review and not more frequently than once in a 12-month period may revise this Exhibit as appropriate to incorporate values which represent then current FCRTS operating conditions or to incorporate any value, used in such Exhibit to calculate the losses, which has changed due to a change in methodology. any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with the Transmission Customer. BPA shall prepare a new Exhibit J incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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AUTHENTICATED

Amendment No. 1
Contract No. 97TX-10031

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

MORGAN STANLEY CAPITAL GROUP INC.

This AMENDMENT to the Transmission Service Agreement, Contract Number 97TX-10031 (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and Morgan Stanley Capital Group Inc. (herein after referred to as "the Transmission Customer") The Transmission Customer and BPA are sometimes referred to individually as "Party", and collectively as "Parties" as the context suggests below.

This Amendment No. 1 (Amendment) to the Agreement between BPA and the Transmission Customer acknowledges the Parties' desire to extend the term of the Agreement to 2400 hours September 30, 2015. The Parties agree that all other terms and conditions of the Agreement remain the same. Article 3 of the Agreement is hereby amended to read as follows:

> "Service under this Service Agreement shall commence at 2400 hours on March 31, 1997. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on September 30, 2015; or (b) 2400 hours on the date of termination established by the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied."

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

MORGAN STANLEY CAPITAL GROUP INC.

By /S/ SIMON GREENSHIELDS

Name Simon Greenshields
(Print/Type)

Title Vice President

Date Jan - 27 - 2001

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /S/ KIPPEN R. MOXNESS
Transmission Account Executive

Name Kippen R. Moxness
(Print/Type)

Date 12-21-2000

(TM-TMC-W:\TMC\CT\Morgan Stanley\10031AA1)

AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission demand of 50 MW from the Big Eddy Substation Point of Interconnection (POI) and to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 16
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 582503

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: at 0000 hours on December 31, 2005.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1,000 kV)	BPA	See Sect. 3 Below		Transmission Customer

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (POI) (Voltage)	Point(s) of Delivery (POD) (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1,000 kV)	01/01/05 - 12/31/05 50 MW	IS-02

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

4. **DESCRIPTION OF POINT(S) OF INTERCONNECTION**

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities to be scheduled.

5. **DESCRIPTION OF POINT(S) OF DELIVERY**

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ PATRICK MURRAY**	By: **/S/ ALAN PASCHKE for**
Name: **Patrick Murray** *(Print/Type)*	Name: Richard A. Gillman *(Print/Type)*
Title: **Vice President**	Title: Transmission Account Executive
Date: **9/4/03**	Date: **8/29/03**

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission service in the amount of 50 MW from the Big Eddy Substation Point of Interconnection (POI) to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 17
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 907059

1. TERM OF TRANSACTION

Start Date: 0000 hours on January 1, 2004.
Termination Date: 0000 hours on January 1, 2006.

The Transmission Customer understands that because of the work Los Angeles Department of Water and Power has currently scheduled on the Celilo (DC Southern Intertie) Modernization Project, the Transmission Provider may not have transmission capacity to provide service under this Table for all or part of the months of October, November and December, 2004 or for all or parts of certain months during 2005 if the work is rescheduled or delayed. The Transmission Customer shall nevertheless pay the full long-term firm PTP transmission service charge based upon a demand of 50 MW plus ancillary service and any other appropriate charges. Also the Transmission Customer shall pay for this transmission service each month during the term of this Table including the months of October, November and December, 2004 and the months during 2005 for which transmission capacity may be unavailable due to the Celilo Modernization Project.

This paragraph is not intended to affect the Transmission Provider's right to curtail service pursuant to the Tariff during any other months or the Transmission Customer's obligation to pay the full transmission service charge and other charges in the event the Transmission Provider curtails transmission service pursuant to the Tariff at any time during 2004 for reasons other than the Celilo Modernization Project.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1,000 kV)	BPA	See Sect. 3 Below		Transmission Customer

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

POI (Voltage)	POD (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1,000 kV)	01/01/04 - 01/01/06 50 MW	IS-04

4. DESCRIPTION OF POINT(S) OF INTERCONNECTION

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities to be scheduled.

5. DESCRIPTION OF POINT(S) OF DELIVERY

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.

By: /S/ PATRICK MURRAY

Name: Patrick Murray
(Print/Type)

Title: Vice President

Date: 11/18/03

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ CLIFFORD C PERIGO

Name: Clifford C. Perigo
(Print/Type)

Title: Senior Transmission Account Executive

Date: 11-12-03

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission demand of 50 MW from the Big Eddy Substation Point of Interconnection (POI) and to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 18
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 1348790

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2008.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	50,000	NOB (1,000 kV)	BPA	50,000		Transmission Customer

3. DESCRIPTION OF POINT(S) OF INTERCONNECTION

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

4. **DESCRIPTION OF POINT(S) OF DELIVERY**

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

5. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

6. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ SIMON GREENSHIELDS**	By: **/S/ YOUNG S. LINN**
Name: **Simon Greenshields** *(Print/Type)*	Name: Young S. Linn *(Print/Type)*
Title: **VP**	Title: Transmission Account Executive
Date: **9/21/04**	Date: **9/17/04**

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EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

This new table provides intertie transmission demand of 50 MW from the Big Eddy Substation Point of Interconnection (POI) and to the Nevada-Oregon Border (NOB) Point of Delivery (POD).

TABLE 19
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (AREF) is: 1348797

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2006.
Termination Date: at 0000 hours on January 1, 2008.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	50,000	NOB (1,000 kV)	BPA	50,000		Transmission Customer

3. DESCRIPTION OF POINT(S) OF INTERCONNECTION

Big Eddy Substation: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

4. **DESCRIPTION OF POINT(S) OF DELIVERY**

Nevada-Oregon Border (NOB): on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

5. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

6. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

MORGAN STANLEY CAPITAL GROUP INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ SIMON GREENSHIELDS**	By: **/S/ YOUNG S. LINN**
Name: **Simon Greenshields** *(Print/Type)*	Name: Young S. Linn *(Print/Type)*
Title: **VP**	Title: Transmission Account Executive
Date: **9/21/04**	Date: **9/17/04**

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Contract No. DE-MS79-87BP92412

SALE AND EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF GLENDALE

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This SALE AND EXCHANGE AGREEMENT, executed as of January 28, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF GLENDALE, CALIFORNIA (Glendale), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Glendale is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Glendale, the City of Burbank (Burbank), the City of Pasadena (Pasadena), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which

provides, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Glendale, Burbank, and Pasadena; and

WHEREAS this Agreement and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Glendale desires to purchase and Bonneville desires to sell surplus firm capacity with energy under the terms specified herein; and

WHEREAS Bonneville and Glendale also desire to enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Term.

This Agreement, when executed, shall become effective at 2400 hours January 31, 1988, and shall terminate at 2400 hours on April 15,

2008; provided, however, that no power sales may occur subsequent to January 31, 2008. All obligations incurred hereunder shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

2(a) "Agreement" means this sale and exchange agreement between Bonneville and Glendale.

2(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

2(c) "Contract Demand" means the maximum hourly rate of delivery for surplus firm power when this Agreement operates as a sale, or for capacity when this Agreement operates as an Exchange. This amount is 5 MW for Block 1 and 5 MW for Block 2, and may be modified by Glendale pursuant to section 4. However, Contract Demand, when used in subsection 7(d), shall mean 10 MW, as may be modified by Glendale pursuant to section 4.

2(d) "Contract Year" means the year beginning at 2400 hours on June 30 and ending at 2400 hours the following June 30.

2(e) "Embedded Transmission Costs" means a charge equal to the Nonfirm Rate portion of Bonneville's IS-87 Southern Intertie Transmission Rate Schedule or successor rate to the extent Glendale uses the Pacific Northwest-Pacific Southwest DC Intertie to provide Supplemental Energy to Bonneville; provided, however, that if the Nonfirm Rate portion of IS-87 or successor rate is terminated prior to the expiration of this Agreement, the Parties agree to use an equivalent substitute value calculated using the same methodology Bonneville used to derive the Nonfirm Rate portion of IS-87. Embedded Transmission Costs also shall include a charge equal to Bonneville's ET-87 Energy Transmission Rate Schedule or successor rate to the extent Glendale provides Supplemental Energy either generated from its resources located outside of Los Angeles County or delivered to Glendale's points of delivery located outside of Los Angeles County.

2(f) "Energy Account" means an account consisting of (i) monthly totals of the amount of Peaking Replacement Energy and Exchange Energy obligated to be delivered to Bonneville during each month, the delivery of which energy Bonneville has declined pursuant to the provisions of paragraph 7(e)(1), and (ii) the value of such declined energy for each month converted to mills/kWh pursuant to paragraph 7(e)(4). For each month there will be two values in the Energy Account: a total amount of energy declined and the value of such energy in mills/kWh.

2(g) "Exchange" means the capacity for energy exchange terms and conditions as described in this Agreement.

2(h) "Exchange Energy" for Block 1 as defined in subsection 5(a) means the energy Glendale is obligated to deliver to Bonneville in equal weekly increments throughout the year in Exchange for Bonneville deliveries of capacity on an annual basis. Exchange Energy for Block 2 as defined in subsection 5(b) means the energy Glendale is obligated to deliver to Bonneville during the period November 16 through April 15 in exchange for Bonneville making available capacity during the preceding May 15 through October 14 period.

2(i) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie transmission lines cross the Nevada-Oregon border.

2(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission capacity due to physical limitations, or (ii) the physical transmission capacity of the DC Intertie is reduced to zero for a period of time which is less than 24-consecutive hours.

2(k) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Glendale during periods when this Agreement operates as an Exchange or capacity sale pursuant to Section 12.

2(l) "Peaking Replacement Energy" means an amount of energy which Glendale is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

2(m) "PNW Coordination Agreement" means the contract among Bonneville and Pacific Northwest (PNW) generating entities, providing for coordinated operation of resources, designated as Contract No. 14-03-48221, as amended or replaced.

2(n) "Supplemental Energy" means the energy Glendale is obligated to make available as a purchase option for Bonneville, pursuant to section 7.

2(o) "Total Incremental Cost" means incremental fuel cost, incremental operation and maintenance, generating unit start-up cost, transmission losses incurred by Glendale in delivering Supplemental Energy to the Point of Delivery, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Glendale in supplying Supplemental Energy to Bonneville that would not otherwise have been incurred.

2(p) "Total Outage" means the physical transmission capacity of the DC Intertie is reduced to zero, whether planned or unplanned, for a period of time which equals or exceeds 24-consecutive hours.

2(q) "UIC" means any unrecoverable incremental costs beyond normal operations incurred by Glendale in generating or acquiring

Supplemental Energy for which Bonneville rescinds its request pursuant to paragraph 7(c)(3). UIC includes, but is not limited to, direct costs, penalties, cancellation fees for fuel commitments, transmission services, or unrecoverable energy purchases, but excludes general engineering, scheduling, and administrative charges. UIC shall not include costs incurred by Glendale to the extent that Glendale is able to make use of such Supplemental Energy and in doing so mitigates costs it has incurred or avoids costs it would otherwise have incurred.

2(r) "Workday" means each day which both Bonneville and Glendale observe as a regular workday.

3. Exhibits.

Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), General Contract Provisions (Form PSC (SW-1)) (Exhibit B), Plan of Delivery (Exhibit C), Minimum Monthly Energy Distribution Tables for Glendale (Exhibit D), and Operating Procedures (Exhibit E) are attached hereto and hereby made a part of this Agreement.

4. Option for Glendale to Increase Purchase.

Not later than June 1, 1988, Glendale, Burbank, and Pasadena may, upon written notice, increase their power purchase by a total of 60 MW, or more, if Bonneville determines power is available for this purpose.

To the extent that any such increase results in an increase for Glendale pursuant to this Agreement, then that increase shall become effective for the Contract Year beginning at 2400 hours on June 30, 1988, and shall be distributed equally to Blocks 1 and 2 for both the surplus firm power sale and Exchange under this Agreement. This Agreement shall be amended as necessary to reflect such increase.

5. Surplus Firm Power Sale.

5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Glendale shall purchase 9,966 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Glendale shall purchase during each Contract Year 24,090 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Glendale shall purchase during each Contract Year while this Agreement remains a power sale, 26,280 MWh of surplus firm energy.

5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available

and Glendale shall purchase 9,180 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing until 2400 hours on June 30, 1992, Glendale shall purchase 2,820 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, and continuing until 2400 hours on October 14, 1992, Glendale shall purchase 6,996 MWh of surplus firm energy. Beginning at 2400 hours on May 14, 1993, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Glendale shall purchase 10,098 MWh of surplus firm energy.

5(c) Adjustments to Amount of Power.

The above MWh quantities for Glendale shall be adjusted as necessary to account for any increase pursuant to section 4. However, in the event of a partial Contract Year power sale for Block 1, or in the event of a partial May 15 through October 14 power sale for Block 2, Glendale shall purchase the appropriate monthly amounts of surplus firm energy under Block 1 and under Block 2 as shown in the applicable plan of delivery for such Contract Year pursuant to subsection 5(e). Glendale may increase the energy scheduled for purchase from Bonneville for any month under the then-current plan of delivery, if such energy is available as determined by Bonneville for such purpose. Such increases shall not affect the plan of delivery, the minimum monthly energy delivery in any future months during such Contract

Year, nor shall any such increase affect the take-or-pay energy amount in any future Contract Year.

5(d) Rates of Delivery.

The maximum hourly rates of delivery for surplus firm power shall be 5 MW from October 15 through May 14 and 10 MW from May 15 through October 14, as may be modified by Glendale's option to increase pursuant to section 4.

5(e) Distribution of Monthly Amounts.

Prior to January 1 of each year, Glendale shall submit a plan of delivery to Bonneville showing the distribution of the monthly amounts of energy for the following 4 Contract Years in the form represented by Exhibit C. Glendale shall distribute the monthly amounts of energy within the limits indicated in Exhibit D.

5(e)(1) If requested by Glendale, Bonneville shall consult with Glendale at the time such plans of delivery are being prepared. Bonneville will share its most recent information on its ability to serve Glendale with a power sale for the following 4 Contract Years and any other considerations that may relate to the plans of delivery. Bonneville shall include such plans of delivery in its PNW Coordination Agreement planning.

5(e)(2) The Parties shall rely upon the most recent plan of delivery submitted to Bonneville for the amount of energy to be delivered in the upcoming July. Bonneville shall notify Glendale at the earliest opportunity, but not later than August 15, if other than that most recent proposed plan of delivery shall become effective for the balance of the Contract Year. Unless otherwise agreed by the Parties, notwithstanding the limits indicated in Exhibit D, the total of the monthly amounts Bonneville shall deliver during July and August shall equal the 2-month July and August total energy amount specified in the plan of delivery ultimately adopted for use during that Contract Year; provided, however, that in the event that Glendale is unable to receive the minimum amount of energy during August due to the timing of such notice, then the Parties shall adjust deliveries as necessary prior to November 16 to provide for any energy not received during August.

5(e)(3) If Bonneville adopts a plan of delivery other than the most recent plan of delivery submitted, Bonneville shall adjust the adopted plan of delivery to reflect the most recent Intermountain Power Project scheduled maintenance outages.

5(f) Distribution of Weekly Amounts.

Within any month, Glendale shall not take more than 135 percent of that month's average weekly amount in any Calendar Week. Such average weekly amount shall be equal to the total MWh for that month as specified in the applicable plan of delivery, divided by the number of days in that month, and multiplied by 7.

5(g) Operational Flexibility.

Glendale may request changes of up to 5 percent of any monthly amount of energy to be made available under the Agreement, with no less than 2 months' advance written notice. Such changes shall not be unreasonably denied by Bonneville, and the ability to make such changes shall be at no additional cost to Glendale. The effect of such changed monthly amount on subsequent monthly amounts of energy shall be included in this notice; provided, however, that changes in monthly amounts purchased hereunder shall not be reduced below the minimum monthly amounts of energy specified in Exhibit D, unless mutually agreed to by the Parties.

6. Conversion to the Exchange.

The sale of surplus firm power shall convert to the Exchange if Bonneville has a surplus firm energy insufficiency under the conditions described in this section; provided, however, that Glendale shall have the option to either: (i) remain in the power sale mode

until after other similar long term sale and exchange agreements executed with parties outside of the Pacific Northwest region for which initial deliveries shall commence after January 1, 1988, have been converted to an exchange; or (ii) convert to the Exchange prior to the conversion of such other similar long term sale and exchange agreements. Glendale shall exercise its option within 14 days after Glendale receives Bonneville's written notice that it will be converting this Agreement or such other similar agreements to an exchange.

6(a) Preliminary Notice.

6(a)(1) If Bonneville determines in the PNW Coordination Agreement planning process that there is a possibility of insufficient surplus firm energy to satisfy the surplus firm energy obligation to Glendale in the next Contract Year, Bonneville shall provide written notice to Glendale as soon as possible. Following this notice, the Parties may, upon mutual agreement, begin the Exchange at 2400 hours on May 14 or on a subsequent date prior to 2400 hours on June 30 of the then-current Contract Year.

6(a)(2) If Bonneville determines in the planning process that there is a certainty of insufficient surplus firm energy for the next Contract Year, Bonneville shall provide written notice to Glendale as soon as possible, but not later than June 15. In this event, regardless of the

extent to which PNW system refill occurs, the Exchange shall begin at 2400 hours on June 30. Glendale's Exchange Energy obligation for Block 2 shall be adjusted to account for a start date of July 1 rather than May 15.

6(b) Final Notice.

If the Exchange does not begin pursuant to subsection 6(a), then the provisions of this subsection apply. The completion of PNW Coordination Agreement planning and the adoption by Bonneville of a particular plan of delivery for Glendale shall occur after July 31. Bonneville shall provide written notice to Glendale as soon as possible after July 31, but not later than August 15, whether service at the Contract Demand shall continue as a power sale or convert to the Exchange. If such notice specifies a conversion to the Exchange, then the Exchange shall begin no sooner than 14 days after the date of receipt of such notice by Glendale. Conversion to the Exchange shall be effective for the remainder of the Contract Year from the time specified in Bonneville's notice to Glendale, or as provided for in subsection 6(c). Glendale's Exchange Energy obligation shall be adjusted to account for the start date specified in the notice rather than May 15.

6(c) Reversion to Power Sale.

After conversion to the Exchange, whenever Bonneville determines that it has sufficient surplus firm energy to deliver the amounts

of surplus firm power specified in subsections 5(a) and 5(b) for the ensuing Contract Year, deliveries under this Agreement shall revert to the surplus firm power sale pursuant to section 5, unless Glendale has provided written notice to Bonneville which describes a contract offer to acquire a resource to replace the energy no longer available from Bonneville due to the conversion to the Exchange. Such notice shall include the amount of energy to be acquired and the term of the proposed acquisition. Bonneville shall respond as follows:

Bonneville shall, within 21 days of receipt of such notice, notify Glendale as to whether this transaction shall revert to the power sale for the duration of Glendale's proposed energy acquisition. If this transaction is to revert to the power sale, Bonneville shall notify Glendale of the basis for the reversion, and such power sale shall begin by the later of (1) 31 days from receipt by Bonneville of Glendale's notice, or (2) the effective date of energy deliveries pursuant to Glendale's proposed acquisition, and shall continue for the duration of Glendale's acquisition, subject to the provisions of section 12. If Bonneville elects not to have the transaction revert to the power sale, then Bonneville shall waive its right to revert to the power sale for the duration of Glendale's contractual commitment for the proposed energy acquisition. Prior to the termination of Glendale's acquisition contract, Bonneville shall, upon written notice of at least 30 days, have the right to revert to the power sale as described in section 5 at the termination of Glendale's acquisition.

6(d) The notice provisions of subsections 6(a) and 6(b) shall apply to reversion from Exchange to power sale, as well as the conversion from power sale to Exchange, except as may be modified by the provisions of subsection 6(c).

7. Capacity For Energy Exchange.

Upon conversion to the Exchange, Bonneville shall make 5 MW of capacity available to Glendale for Block 1 on an annual basis and 5 MW of capacity for Block 2 from May 15 through October 14 each year, as may be modified by Glendale's option to increase pursuant to section 4. Glendale shall be obligated to deliver Peaking Replacement Energy to Bonneville during these periods of capacity deliveries as specified in subsection 7(a). In Exchange for Bonneville deliveries of capacity, Glendale shall deliver Exchange Energy and make available Supplemental Energy to Bonneville, as specified in subsections 7(b) and 7(c).

7(a) Deliveries of Capacity and Peaking Replacement Energy.

At times when the Exchange is in effect, Bonneville shall make available to Glendale capacity in an amount up to the Contract Demand each hour, up to 10 hours times the Contract Demand each day Monday through Saturday, including holidays, not to exceed 50 hours times the Contract Demand each week. Glendale shall be obligated to deliver to Bonneville Peaking Replacement Energy for the amounts of Peaking Energy delivered to Glendale by 2400 hours

on the day following the Peaking Energy delivery, except as provided in subsection 7(e). Return of Peaking Replacement Energy during any hour shall not exceed 100 percent of the Contract Demand in any hour, unless otherwise mutually agreed by the parties.

7(b) Exchange Energy.

Glendale shall be obligated to deliver Exchange Energy to Bonneville as provided herein. The amount of such energy provided each Contract Year shall equal the exchange ratio in kWh/kW for each block of capacity, multiplied by the Contract Demand in kilowatts for each block of capacity. For Block 1, the exchange ratio is 2,536 kWh/kW; for Block 2, the exchange ratio is 975 kWh/kW. Exchange Energy for Block 1 shall be delivered in equal weekly increments throughout the year and Exchange Energy for Block 2 shall be delivered in equal weekly increments from November 16 through April 15, except as provided in subsection 7(e). Such equal weekly increments shall be adjusted as necessary to account for an uneven number of weeks during any Exchange Energy delivery period. In the event of a partial Contract Year of capacity deliveries, the amount of Exchange Energy which Glendale is obligated to deliver to Bonneville shall be reduced on a pro rata basis to account for such partial Contract Year.

7(c) Supplemental Energy.

7(c)(1) Glendale shall be obligated to make Supplemental Energy available to Bonneville during each November 16 through April 15 while this Agreement operates as an Exchange. The total amount of such energy provided each Contract Year shall equal the supplemental ratio in kWh/kW multiplied by the Block 2 Contract Demand in kilowatts of capacity. The supplemental ratio is 1,200 kWh/kW. Bonneville may elect to purchase up to the maximum amount of Supplemental Energy available to Bonneville in any Contract Year by serving a notice to Glendale not less than 2 months prior to the desired delivery date, or on shorter notice if agreed to by Glendale. Bonneville may issue additional notices during any Contract Year for amounts of Supplemental Energy not previously requested in a notice. Any such notice shall specify the amount of Supplemental Energy desired by Bonneville and provide a nonbinding proposed schedule for deliveries of Supplemental Energy. Glendale shall promptly notify Bonneville if such proposed schedule is unacceptable to Glendale and the reasons therefor. Glendale shall not unreasonably deny Bonneville's proposed schedule. In the event that the Parties are unable to agree on a proposed schedule, then the requested Supplemental Energy shall be delivered in equal hourly increments during the delivery period specified in Bonneville's notice and during the

hours specified in paragraph 7(d)(3). Bonneville and Glendale shall finalize the schedule for deliveries of weekly blocks of Supplemental Energy within 15 Workdays of receipt by Glendale of Bonneville's notice. Deliveries of Supplemental Energy are subject to Glendale's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Glendale's generation or transmission capability. In the event of any such constraints, Glendale shall reschedule such deliveries in a timely manner. In the event of an extended generation constraint, Bonneville may request an alternate available source for Supplemental Energy at another agreed upon price, until such time as the generation constraint is removed.

7(c)(2) Within 15 Workdays of receipt of Bonneville's notice requesting to make available Supplemental Energy, and prior to committing to obtain Supplemental Energy, Glendale shall inform Bonneville of probable resources available, including the estimated price of the lowest cost sources of Supplemental Energy available for purchase, the estimated Total Incremental Cost from such sources, and the UIC for such resources. Glendale shall revise such estimated price, Total Incremental Cost, and UIC if conditions change substantially during the remaining days of the notice period described in

paragraph 7(c)(1). If Glendale determines that the UIC from such sources will exceed 4.5 mills, as escalated pursuant to subsection 9(c), it shall notify Bonneville, and Bonneville shall have the option of either: (1) raising such maximum rate for UIC; (2) relieving Glendale of its obligation to provide Supplemental Energy; or (3) obligating itself to purchase Supplemental Energy. Bonneville shall make this choice in a timely manner. Glendale shall use best efforts to mitigate UIC, but unless earlier notification by Glendale and Bonneville's selection of its option to raise the maximum rate for UIC has occurred, Bonneville's obligation for the amount of energy specified in its notice of rescission shall not exceed 4.5 mills/kWh as escalated pursuant to subsection 9(c).

7(c)(3) Bonneville shall pay Glendale any applicable Embedded Transmission Costs plus 115 percent of Glendale's Total Incremental Cost for providing Supplemental Energy. Bonneville may rescind a notice requesting Supplemental Energy not later than 0930 hours of the Workday immediately preceding the day when such Supplemental Energy was to begin to be provided to Bonneville, and pay Glendale any UIC incurred by Glendale in response to Bonneville's previous request for such energy. Any decision to rescind a notice requesting Supplemental Energy shall apply to the total amount of MWh of

Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1); provided, however, that Bonneville can rescind a portion of the Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1) if Bonneville agrees to pay any new UIC resulting therefrom.

7(c)(4) Bonneville shall submit schedules for the delivery of Supplemental Energy pursuant to the provisions of paragraph 7(c)(1) and section 10. Glendale shall not unreasonably withhold its agreement with such schedules, and Glendale shall deliver weekly amounts of Supplemental Energy by the end of each Calendar Week during the period of deliveries pursuant to the mutually agreed upon schedules for the delivery of Supplemental Energy.

7(d) Delivery Limitations.

7(d)(1) May 15 through October 14.

Unless limited by Bonneville, Glendale shall complete each Calendar Week's deliveries of Exchange Energy by the end of such Calendar Week. The maximum rate of delivery for Peaking Replacement Energy plus Exchange Energy shall be 100 percent of the Contract Demand. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account. Bonneville may limit the delivery rate for

Peaking Replacement Energy plus Exchange Energy to not less than 60 percent of Contract Demand for the Exchange during the period May 15 through October 14. To the extent that Bonneville restricts the delivery on any hour, the restricted quantity of Peaking Replacement Energy and Exchange Energy may either be delivered by Glendale on hours other than the hours specified in paragraph 7(d)(3), or be delivered on the next available normal delivery hour when Bonneville can accept such energy. The Parties may agree to delay the delivery beyond the Calendar Week of delivery, or the Parties may agree to place such energy into the Energy Account, as described in paragraph 7(e)(1).

7(d)(2) November 16 through April 15.

Hourly rates of delivery shall be as mutually agreed upon by Bonneville and Glendale. However, during the period November 16 through April 15, during any hour the total rate of delivery for Exchange Energy plus Supplemental Energy plus Peaking Replacement Energy shall not exceed 250 percent of the Contract Demand, unless mutually agreed to by Bonneville and Glendale. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account.

7(d)(3) Normal Delivery Hours for Peaking Replacement and Exchange Energy.

Although deliveries of Peaking Replacement Energy and Exchange Energy may occur during other hours, the normal delivery hours are as follows:

2200 hours on Monday to 0800 hours on Tuesday
2200 hours on Tuesday to 0800 hours on Wednesday
2200 hours on Wednesday to 0800 hours on Thursday
2200 hours on Thursday to 0800 hours on Friday
2200 hours on Friday to 0800 hours on Saturday
2200 hours on Saturday to 0800 hours on Monday.

7(e) Conditions for Energy Account and Cash-Out of Peaking Replacement and Exchange Energy.

7(e)(1) Declinations of Peaking Replacement Energy and Exchange Energy.

Bonneville may decline deliveries of either Peaking Replacement Energy or Exchange Energy in whole or in part. Bonneville shall provide Glendale with notice by 1400 hours on the Thursday prior to each Calendar Week. Such notice shall specify whether Bonneville will require the delivery of such energy in whole or in part for the next Calendar Week and shall specify the amount of energy which Bonneville declines. To the extent that Bonneville declines the deliveries, the monthly total of such declined energy and its value converted to mills/kWh

pursuant to paragraph 7(e)(4) shall be entered into the Energy Account.

7(e)(2) Withdrawals from the Energy Account.

Bonneville may request to withdraw energy from the Energy Account during a Calendar Week and shall provide Glendale with notice by 1400 hours on the Thursday prior to such Calendar Week. Such notice shall specify the quantity of energy to be withdrawn and the rate of delivery for such energy. However, in addition to other deliveries by Glendale pursuant to this Agreement, the maximum rate of withdrawal from the Energy Account shall not exceed the Contract Demand on any hour, unless mutually agreed. Glendale shall provide such requested energy to Bonneville during the next Calendar Week, subject to Glendale's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Glendale's generation or transmission capability. The value for energy withdrawn from the Energy Account shall be converted to kWh as determined pursuant to paragraph 7(e)(4) and shall be withdrawn on a first-in-first-out basis. To the extent that the value for withdrawn energy is greater than the value for declined energy determined pursuant to paragraph 7(e)(1), Bonneville shall pay Glendale an amount equal to the

difference between the values for withdrawn and declined energy multiplied by the kWh withdrawn. To the extent that the value for withdrawn energy is less than the value for declined energy determined pursuant to paragraph 7(e)(1), Glendale shall pay Bonneville an amount equal to the difference between the values for declined and withdrawn energy multiplied by the kWh withdrawn. Each party shall pay the other pursuant to the provisions of section 8. If mutually agreed, withdrawn energy may be provided on hours other than those specified in paragraph 7(d)(3).

7(e)(3) Cash-Out of Energy in the Energy Account.

Bonneville shall maintain the Energy Account. The Energy Account shall contain monthly totals of (i) the declined energy remaining at the end of each calendar month, and (ii) the value of such energy converted to mills/kWh pursuant to paragraph 7(e)(4). Any monthly total of energy which remains in the Energy Account longer than 11 months shall be cashed out pursuant to subsection 9(b) at the cash-out price at the time the energy was entered into the Energy Account. No more than one monthly total of energy shall be cashed out on any monthly bill rendered to Glendale. Glendale shall pay Bonneville pursuant to the cash-out terms specified in subsection 9(b), and shall be relieved of any obligation

thereafter to provide such monthly total of energy to Bonneville.

7(e)(4) Determination of Value for Energy Entered into Energy Account and Withdrawn from Energy Account.

Following receipt of its gas bill each month, Glendale shall provide Bonneville with a copy of a portion of such bill which shows the dollars per dekatherm paid by Glendale for the total of all gas purchases for that month. Bonneville shall convert this amount to dollars per Btu and apply this ratio to an agreed-upon heat rate of 10,000 Btu per kWh to determine the value in mills per kWh for entries into and withdrawals from the Energy Account during the following month. To the extent that gas is not available or is no longer a significant fuel source for generation by Glendale, the Parties shall negotiate: (i) an alternate significant fuel source which is used by Glendale for generation; and (ii) a methodology to derive a value in mills/kWh for entries into and withdrawals from the Energy Account. This Agreement shall be amended to implement the results of such negotiation.

7(f) At Glendale's request, the Parties agree to negotiate in good faith mutually agreeable terms and conditions which would allow Glendale to deliver energy to Bonneville's system for later use by Glendale.

8. Payment.

8(a) Payment by Glendale.

Bonneville shall render preliminary and final adjusted monthly bills to Glendale. Glendale shall pay Bonneville by the close of business on the twentieth (20th) day after the date of each such preliminary bill and any adjustments that may occur on the final monthly bill. The date of such bills shall be no earlier than the mailing date of such bills. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Glendale, then the due date shall be the next following business day. Other provisions related to payment of bills shall be in accordance with the General Rate Schedule Provisions attached to this Agreement.

8(b) Payment by Bonneville.

Glendale shall render monthly bills to Bonneville. Bonneville shall pay Glendale by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to payment of bills shall be in accordance with the General Rate Schedule provisions attached to this Agreement.

9. Rates and Cash-Out.

9(a) Surplus Firm Power.

9(a)(1) Initial Demand and Energy Rates.

The initial demand and energy rates for deliveries of power under Block 1 and Block 2 are as follows: $4.60/kilowatt-month (kW-mo.) and 20.5 mills/kWh (includes Intertie adder). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery.

9(a)(2) Rate Adjustment During First 5 Years.

The initial demand and energy rates for the period January 1, 1988, through December 31, 1988, are described in paragraph 9(a)(1). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. The energy rates specified in this paragraph 9(a)(2) include the Intertie adder. The rates for calendar years 1989 through 1992 are as follows:

Calendar Year	Capacity ($/kW-mo.)	Energy (mills/kWh)
1989	4.88	21.73
1990	5.17	23.03
1991	5.48	24.42
1992	5.81	25.88

Subsequent to December 31, 1992, the demand and energy rates shall be adjusted pursuant to paragraph 9(a)(3).

9(a)(3) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

Adjustments under this paragraph begin January 1, 1993. For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. On the effective date of any Bonneville Priority Firm Power (PF) rate adjustment thereafter, the rate for surplus firm power (SL_{new}) shall be adjusted as follows:

$$SL_{new} = SL_n * \frac{PF_{new}}{PF_{prev}}$$

where

SL_{new} = The effective surplus firm power demand and energy charges hereunder as adjusted to reflect the change between PF_{new} and PF_{prev}.

SL_n = For the initial adjustment under this paragraph 9(a)(3) the SL_n demand charge shall be $5.81/kW-mo. and the energy charge shall be 25.88 mills/kWh. For all subsequent adjustments under this paragraph, the values for SL_n shall be the then-current values for the previous SL_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be

determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh, in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(b) Cash-out.

Bonneville shall cash out energy pursuant to paragraph 7(e)(3). Glendale shall pay Bonneville for such energy as provided below.

9(b)(1) Initial Cash-out.

The initial level for cash-out shall be 14.9 mills/kWh.

9(b)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any PF rate adjustment after the effective date of this Agreement, the level of the cash-out rate (CO_{new}) shall be adjusted as follows:

$$CO_{new} = CO_n * \frac{PF_{new}}{PF_{prev}}$$

where CO_{new} = The effective level for cash-out as adjusted to reflect a new PF rate.

CO_n = For the initial adjustment under this paragraph 9(b)(2), CO_n shall be 14.9 mills/kWh. For all subsequent adjustments under this paragraph, the values for CO_n shall be the then-current values for the previous CO_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(c) Maximum Rate for UIC Incurred by Glendale if Bonneville Rescinds a Notice for Supplemental Energy.

9(c)(1) Initial Maximum Rate for UIC.

In accordance with subsection 7(c), the initial rate for UIC is 4.5 mills/kWh for the amount of energy specified in Bonneville's notice of rescission.

9(c)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any Priority Firm Power (PF) rate adjustment after the effective date of this

Agreement, the maximum rate for UIC (UIC_{new}) shall be adjusted as follows:

$$UIC_{new} = UIC_n * \frac{PF_{new}}{PF_{prev}}$$

where

UIC_{new} = The effective rate for UIC as adjusted to reflect a new PF rate.

UIC_n = For the initial adjustment under this paragraph 9(c)(2), UIC_n shall be equal to 4.5 mills/kWh. For all subsequent adjustments under this paragraph, the values for UIC_n shall be the then-current values for the previous UIC_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

10. Scheduling Provisions for Power Sale and Exchange.

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

10(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

10(b) Prescheduled amounts shall be submitted by 0930 hours.

10(c) This subsection 10(c) shall apply only to the power sale portion of this transaction. If Glendale desires to schedule other than that month's average weekly amount of energy for such month in any Calendar Week, Glendale shall notify Bonneville by 1400 hours on the Monday preceding such Calendar Week. Glendale may revise such new weekly amount if Glendale notifies Bonneville by 1400 hours on the Thursday preceding such Calendar Week.

10(d) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts that Glendale anticipates it will schedule from Bonneville each day for the following 10 days. Glendale shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Glendale or Bonneville to schedule such amounts.

10(e) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such changes

shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

11. Transmission Limitation.

In the event of an interruption of deliveries by either Party due to a DC Intertie outage, the following provisions shall apply.

11(a) Relief Remedies During Periods of Total Outage.

The Parties shall be relieved of obligations as follows.

11(a)(1) Conditions for Capacity Payment Relief.

The following conditions must be met each Contract Year for relief to be given as described in paragraph 11(a)(2): (i) the duration of a single Total Outage exceeds 360-consecutive hours, in which case relief is provided for the remainder of such Total Outage only; or (ii) the sum of all Total Outages for the Contract Year exceeds 720 hours, excluding Total Outages, if any, for which relief was given pursuant to item (i) above.

11(a)(2) Determination of Capacity Payment Relief.

For the duration of the Total Outages which occur subsequent to the occurrence of relief as described in

paragraph 11(a)(1), Glendale shall receive a capacity credit in the form of a reduction in the demand rate per kW-mo. calculated by determining such duration of the Total Outage during the billing month, divided by the total number of hours in that month.

11(a)(3) Energy Payment Relief During Power Sale.

Without regard to the duration of a Total Outage, if Glendale is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Glendale shall be relieved of its obligation to pay for such amounts of energy. To the extent that Glendale is unable to receive energy during any month, the monthly minimum take-or-pay energy specified in the applicable plan of delivery shall be reduced by an amount of energy determined as follows: a ratio shall be calculated, the numerator being the number of hours of Total Outage during the month that Glendale is unable to receive energy, and the denominator being the total number of hours in that month. This ratio is then multiplied by the monthly energy specified in the applicable plan of delivery to determine such amount of energy. This amount of energy shall be subtracted from such monthly energy to determine the revised monthly amount for that month. The total take-or-pay energy for Block 1, or Block 2 if

applicable, as specified in Exhibit D, shall be reduced by the amount of energy as calculated above.

11(a)(4) Energy Payment Relief During Exchange.

11(a)(4)(A) For Total Outages which occur subsequent to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Glendale's obligation to deliver Peaking Replacement Energy owed to Bonneville for previous capacity delivered by Bonneville, and Supplemental Energy requested by Bonneville pursuant to subsection 7(c) remain. Glendale's obligation to deliver Exchange Energy associated with a Total Outage up to one year remains, but, at Bonneville's option, either: (i) Glendale shall deliver such energy to Bonneville subject to mutually agreed upon schedules following the end of the Total Outage and Bonneville shall pay Glendale's Total Incremental Cost for the first 3 months of such obligation and 115 percent of Glendale's Total Incremental Cost for the following 9 months; or (ii) Glendale shall be relieved of its obligation to deliver such energy.

11(a)(4)(B) For Total Outages which occur prior to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Glendale shall reschedule deliveries of Peaking Replacement Energy, Exchange Energy, and Supplemental Energy which Glendale is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the Total Outage, or at other times as mutually agreed by the Parties.

11(b) Relief Remedies During Periods of Partial Outage.

11(b)(1) Relief Remedies During the Power Sale.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue deliveries under this Agreement. The Parties also shall curtail pro rata on an hourly basis all agreements executed on or before January 1, 1988, for firm energy or capacity based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over agreements executed after January 1, 1988 for firm energy or capacity. If Glendale is unable to receive any amounts of energy, Bonneville shall be relieved of

its obligation to deliver and Glendale shall be relieved of its obligation to pay for such amounts of energy.

11(b)(2) Relief Remedies During the Exchange.

During the Exchange, or during any period of the power sale when Bonneville has restricted surplus firm energy deliveries pursuant to section 12 and is delivering capacity only, the following provisions shall apply.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue or reschedule deliveries under this Agreement. The Parties shall curtail all agreements for firm capacity without energy or deliveries of exchange energy executed prior to January 1, 1988, pro rata on an hourly basis, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over deliveries of capacity or exchange energy pursuant to agreements executed after January 1, 1988. Glendale shall reschedule interrupted or curtailed deliveries of Peaking Replacement Energy, Exchange Energy and Supplemental Energy which Glendale is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the

interruption or curtailment, or at other times and under conditions as mutually agreed by the Parties.

12. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of 16 U.S.C. § 837 (1984) (P.L. 88-552), and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to those provisions, Bonneville shall have the right to restrict all or a portion of the capacity or energy if such capacity or energy is needed to meet the capacity or energy requirements, as the case may be, in the PNW. Such restrictions shall be limited in amounts and duration to cover the projected need specified in the written notice which Bonneville shall provide to Glendale. The sale of surplus firm power shall resume pursuant to the applicable plan of delivery for the remainder of the then-current Contract Year after expiration of the period of restriction except as described in the immediately following sentence. If a projected period of restriction exceeds 2 months' duration, Glendale may make other arrangements for energy for the remainder of such Contract Year if Glendale has entered into a contractual commitment with a third party as a direct result of Bonneville's prior notice of restriction, and Bonneville has received Glendale's written notice of such arrangements not later than 10 days prior to the projected end of such period of restriction.

uch written otice shall pecify the date n which a eriod of estriction begins nd the date on hich such period f restriction is rojected to end.

During any period that Bonneville continues to have surplus firm energy on a planning basis, but Bonneville restricts the delivery of

energy as provided above, Bonneville shall make available capacity at the Contract Demand and, in the event of a partial energy restriction, a pro rata amount of energy. Prior to the effective date of the restriction, Glendale shall give notice to Bonneville of the amount of capacity made available by Bonneville that Glendale desires for the anticipated duration of the restriction. In such notice, Glendale may reduce the amount of capacity it desires for the anticipated period of restriction below the Contract Demand, with no change in the rate per kW-mo. of capacity specified in section 9; provided, however, that if Glendale reduces the amount of capacity it desires during a period of restriction to zero, and the reduction to zero capacity occurs on any day other than the last day of a month, then Bonneville shall make a pro rata reduction in the rate per kW-mo. of capacity. Terms for the delivery of such capacity and for the cash-out or delivery of Peaking Replacement Energy shall be as provided in this Agreement.

13. Points of Delivery.

13(a) Points of Delivery.

The point of delivery for all deliveries pursuant to this Agreement is NOB.

13(b) Other Pacific Southwest Points of Delivery.

Notwithstanding the point of delivery specified in subsection 13(a), at Bonneville's request, Glendale shall

deliver energy owed Bonneville to Pacific Southwest points of delivery where Glendale has interconnections and available transmission capacity with Pacific Southwest utilities.

13(c) Costs Incurred to Point of Delivery.

Each Party shall bear its own costs for deliveries to the point of delivery under subsections 13(a) and 13(b); provided, however, that all deliveries of Supplemental Energy by Glendale to Bonneville pursuant to subsection 7(c) shall be excluded from the provisions of this subsection.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ James J. Jura
Administrator

Date January 28, 1988

CITY OF GLENDALE, CALIFORNIA

By /s/ David Ramsay

Title Asst. City Manager

Date 11/25/87

14. Limit of Liability.

It is mutually understood and agreed that Glendale's obligations for the payment of monies pursuant to this Agreement are limited to revenues received by Glendale from the sale of electric power and/or the disposition of assets of Glendale's power generation and transmission facilities.

PLAN OF DELIVERY

1. Monthly Amounts of Energy Requested by Glendale Pursuant to Subsection 5(e).

Year / Month	1988	1989	1990	1991
July				
August				
September				
October				
November				
December				
January				
February				
March				
April				
May				
June				

This attachment will be revised each year upon Glendale's submission of new data.

2. Example, assuming 1992 Power Sale.

Upon Glendale's submittal of plans of delivery each year in accordance with subsection 5(e), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations. Assuming energy sufficient to serve Glendale load as a power sale, the plan of delivery to be used is based upon the degree to which the coordinated system refills.

At 2400 hours on July 31, 1992, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will implement the most recent plan of delivery submitted by Glendale. If the system does not refill, such parties will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier "Critical Periods"). This can be shown as follows:

Critical Period	Glendale's Plan of Delivery
1992 - 1995 (refill)	year 1992 from 1992 submittal
1991 - 1994	year 1992 from 1991 submittal
1990 - 1993	year 1992 from 1990 submittal
1989 - 1992	year 1992 from 1989 submittal

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 5 MW DEMAND			BLOCK 2: 5 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	30%	= 1,116					1,116
F	30%	= 1,008					1,008
M	40%	= 1,488					1,488
A	50%	= 1,800					1,800
M	55%	= 2,046	May (15-31)	50%	= 1,020		3,066
J	55%	= 1,980		50%	= 1,800		3,780
J	65%	= 2,418 1/		50%	= 1,860 1/		4,278
A	65%	= 2,418 1/		55%	= 2,046 1/		4,464 2/
S	65%	= 2,340		50%	= 1,800		4,140
O	50%	= 1,860	Oct. (1-14)	15%	= 252		2,112
N	30%	= 1,080					1,080
D	30%	= 1,116					1,116
TOTAL		20,670			8,778		
TAKE-OR-PAY		24,090 3/			9,180 3/		
BLOCK 1 LF = 55%				BLOCK 2 LF = 50%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).
3/ These figures will be increased on July 1, 1992, pursuant to page 2 of this Exhibit D.

(WP-PKLD-3464c)

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 5 MW DEMAND			BLOCK 2: 5 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	30%	= 1,116					1,116
F	30%	= 1,008					1,008
M	40%	= 1,488					1,488
A	50%	= 1,800					1,800
M	55%	= 2,046	May (15-31)	50%	= 1,020		3,066
J	55%	= 1,980		50%	= 1,800		3,780
J	65%	= 2,418 1/		50%	= 1,860 1/		4,278
A	65%	= 2,418 1/		55%	= 2,046 1/		4,464 2/
S	65%	= 2,340		50%	= 1,800		4,140
O	50%	= 1,860	Oct. (1-14)	15%	= 252		2,112
N	30%	= 1,080					1,080
D	30%	= 1,116					1,116
TOTAL		20,670			8,778		
TAKE-OR-PAY		26,280			10,098		
BLOCK 1 LF = 60%				BLOCK 2 LF = 55%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

(WP-PKLD-3464c)

OPERATING PROCEDURES

No operating procedures have been established as of the date of execution of this Agreement.

Prior to conversion to the Exchange, the Parties agree to develop operating procedures which shall be utilized during the Exchange. Such procedures shall include, but are not limited to, determination and verification of Total Incremental Cost, determination and verification of UIC, operating procedures under the Energy Account, and operating procedures during periods of Total Outage and Partial Outage.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in this Agreement.

Amendatory Agreement No.1
Contract No. DE-MS79-87BP92412

June 14, 1988

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF GLENDALE

This AMENDATORY AGREEMENT, executed as of July 8, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF GLENDALE, CALIFORNIA (Glendale), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Glendale is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS on January 28, 1988, Glendale and Bonneville executed Contract No. DE-MS79-87BP92412 (Sale and Exchange Agreement), which provides, among other things, for Bonneville to sell surplus firm capacity with energy to Glendale; and

WHEREAS the Sale and Exchange Agreement also provides that Bonneville and Glendale shall enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS in accordance with the provisions of section 4 of the Sale and Exchange Agreement, Glendale has exercised its option to increase the power purchase from 5 MW for Block 1 and 5 MW for Block 2 to 10 MW for Block 1 and 10 MW for Block 2; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Effective Date of Amendatory Agreement.

This Amendatory Agreement, when executed, shall become effective at 2400 hours on June 30, 1988.

2. Amendment of Sale and Exchange Agreement.

The Sale and Exchange Agreement, Contract No. DE-MS79-87BP92412, is hereby amended as follows:

(a) Subsection 5(a) is deleted and replaced by the following:

"5(a) Amounts of Power Under the Annual Sale (Block I).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Glendale shall purchase 9,966 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Glendale shall purchase during each Contract Year 48,180 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and

Glendale shall purchase during each Contract Year while this Agreement remains a power sale, 52,560 MWh of surplus firm energy."

(b) Subsection 5(b) is deleted and replaced by the following:

"5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Glendale shall purchase 2,820 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on October 14, 1988, Bonneville shall make available and Glendale shall purchase 12,720 MWh of surplus firm energy.

Beginning at 2400 hours on May 14, 1989, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Glendale shall purchase 18,360 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at

2400 hours on May 14, 1992, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Glendale shall purchase 20,196 MWh of surplus firm energy."

(c) Exhibit D, which was effective at 2400 hours on January 31, 1988, is deleted and replaced by the attached Exhibit D.

3. Signature Clause The signatories hereto represent that they have been appropriately authorized to enter this Amendatory Agreement behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Amendatory Agreement

CITY OF GLENDALE
DATE 7/1/88
APPROVED AS TO FINANCIAL PROVISION FOR $1,400,000 est. pay as you go
Director of Finance

CITY OF GLENDALE, CALIFORNIA
By
Title City Manager
Date 7/8/88

(VS6-PMC-3730c)

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By
Administrator
Date JUN 2 8 1988

APPROVED AS TO FORM
Assistant City Attorney
DATE 6-30-88

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 10 MW DEMAND			BLOCK 2: 10 MW DEMAND			TOTAL MWh
	LF	=	MIN. MWh	LF	=	MIN. MWh	
J	30%	=	2,232				2,232
F	30%	=	2,016				2,016
M	40%	=	2,976				2,976
A	50%	=	3,600				3,600
M	55%	=	4,092	May (15-31) 50%	=	2,040	6,132
J	55%	=	3,960	50%	=	3,600	7,560
J	65%	=	4,836 1/	50%	=	3,720 1/	8,556
A	65%	=	4,836 1/	55%	=	4,092 1/	8,928 2/
S	65%	=	4,680	50%	=	3,600	8,280
O	50%	=	3,720	Oct. (1-14) 15%	=	504	4,224
N	30%	=	2,160				2,160
D	30%	=	2,232				2,232
TOTAL			41,340			17,556	
TAKE-OR-PAY			48,180 3/			18,360 3/	
BLOCK 1 LF = 55%				BLOCK 2 LF = 50%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).
3/ These figures will be increased in 1992, pursuant to page 2 of this Exhibit D.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR GLENDALE

	BLOCK 1: 1/ 10 MW DEMAND			BLOCK 2: 10 MW DEMAND			TOTAL MWh
	LF	= MIN. MWh		LF	= MIN. MWh		
J	30%	= 2,232					2,232
F	30%	= 2,016					2,016
M	40%	= 2,976					2,976
A	50%	= 3,600					3,600
M	55%	= 4,092	May (15-31)	50%	= 2,040		6,132
J	55%	= 3,960		50%	= 3,600		7,560
J	65%	= 4,836 2/		50%	= 3,720 2/		8,556
A	65%	= 4,836 2/		55%	= 4,092 2/		8,928 3/
S	65%	= 4,680		50%	= 3,600		8,280
O	50%	= 3,720	Oct. (1-14)	15%	= 504		4,224
N	30%	= 2,160					2,160
D	30%	= 2,232					2,232
TOTAL		41,340			17,556		
TAKE-OR-PAY		52,560			20,196		
BLOCK 1 LF = 60%				BLOCK 2 LF = 55%			

1/ The total take-or-pay energy amount for Block 1 shall be effective at 2400 hours on June 30, 1992.
2/ July and August in both Blocks have maximum load factors of 75%.
3/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).

EXHIBIT C
CONTRACT NO. DE-MS79-87BP92412
CITY OF GLENDALE

PLAN OF DELIVERY

Monthly Amounts of Surplus Firm Energy (in MWH)

BLOCK # 1

Contract Year:	2000/01	2001/02	2002/03	2003/04
Month				
July	5,580	5,580	5,580	5,580
August	5,580	5,580	5,580	5,580
September	5,360	5,360	5,360	5,360
October	4,100	4,100	4,100	4,100
November	3,225	3,225	3,225	3,225
December	3,310	3,310	3,310	3,310
January	4,420	4,420	4,420	4,420
February	3,925	3,925	3,925	3,925
March	3,575	3,575	3,575	3,575
April	4,060	4,060	4,060	4,060
May	4,600	4,600	4,600	4,600
June	4,825	4,825	4,825	4,825
TOTAL:	52,560	52,560	52,560	52,560

BLOCK # 2

Delivery Period	2001	2002	2003	2004
Month				
May (15-31)	2,240	2,240	2,240	2,240
June	3,960	3,960	3,960	3,960
July	4,090	4,090	4,090	4,090
August	4,940	4,940	4,940	4,940
September	4,400	4,400	4,400	4,400
October (01-14)	566	556	556	566
TOTAL:	20,196	20,196	20,196	20,196

(AUTHENTICATED COPY)

Contract No. DE-MS79-87BP92411

SALE AND EXCHANGE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF BURBANK

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Exhibit A (Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions)..... 8

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Exhibit C (Plan of Delivery)..... 8

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This SALE AND EXCHANGE AGREEMENT, executed as of January 28, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF BURBANK, CALIFORNIA (Burbank), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Burbank is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS Burbank, the City of Glendale (Glendale), the City of Pasadena (Pasadena), Portland General Electric Company (Portland), and Bonneville executed a memorandum of understanding (Contract No. DE-MS79-87BP92376), which provides, among other things, for Bonneville and Portland to cooperate in order to provide various power and exchange services to Burbank, Glendale, and Pasadena; and

WHEREAS this Agreement and certain other agreements have been developed in order to implement the terms and conditions of Contract No. DE-MS79-87BP92376; and

WHEREAS Burbank desires to purchase and Bonneville desires to sell surplus firm capacity with energy under the terms specified herein; and

WHEREAS Bonneville and Burbank also desire to enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Term.

This Agreement, when executed, shall become effective at 2400 hours January 31, 1988, and shall terminate at 2400 hours on April 15, 2008; provided, however, that no power sales may occur subsequent to January 31, 2008. All obligations incurred hereunder shall be preserved until satisfied.

2. Definitions.

The following terms, when used in this Agreement with initial capitalization, whether singular or plural, shall have the meanings specified:

2(a) "Agreement" means this sale and exchange agreement between Bonneville and Burbank.

2(b) "Calendar Week" means the week beginning at 2400 hours on Saturday, and ending at 2400 hours on the following Saturday.

2(c) "Contract Demand" means the maximum hourly rate of delivery for surplus firm power when this Agreement operates as a sale, or for capacity when this Agreement operates as an Exchange. This amount is 9 MW for Block 1 and 9 MW for Block 2, and may be modified by Burbank pursuant to section 4. However, Contract Demand, when used in subsection 7(d), shall mean 18 MW, as may be modified by Burbank pursuant to section 4.

2(d) "Contract Year" means the year beginning at 2400 hours on June 30 and ending at 2400 hours the following June 30.

2(e) "Embedded Transmission Costs" means a charge equal to the Nonfirm Rate portion of Bonneville's IS-87 Southern Intertie Transmission Rate Schedule or successor rate to the extent Burbank uses the Pacific Northwest-Pacific Southwest DC Intertie to provide Supplemental Energy to Bonneville; provided, however, that if the Nonfirm Rate portion of IS-87 or successor rate is terminated prior to the expiration of this Agreement, the Parties agree to use an equivalent substitute value calculated using the same methodology Bonneville used to derive the Nonfirm Rate portion of IS-87. Embedded Transmission Costs also shall include a charge equal to Bonneville's ET-87 Energy Transmission Rate Schedule or successor rate to the extent Burbank provides Supplemental Energy either generated from its resources located outside of Los Angeles County or delivered to Burbank's points of delivery located outside of Los Angeles County.

2(f) "Energy Account" means an account consisting of (i) monthly totals of the amount of Peaking Replacement Energy and Exchange Energy obligated to be delivered to Bonneville during each month, the delivery of which energy Bonneville has declined pursuant to

the provisions of paragraph 7(e)(1), and (ii) the value of such declined energy for each month converted to mills/kWh pursuant to paragraph 7(e)(4). For each month there will be two values in the Energy Account: a total amount of energy declined and the value of such energy in mills/kWh.

2(g) "Exchange" means the capacity for energy exchange terms and conditions as described in this Agreement.

2(h) "Exchange Energy" for Block 1 as defined in subsection 5(a) means the energy Burbank is obligated to deliver to Bonneville in equal weekly increments throughout the year in Exchange for Bonneville deliveries of capacity on an annual basis. Exchange Energy for Block 2 as defined in subsection 5(b) means the energy Burbank is obligated to deliver to Bonneville during the period November 16 through April 15 in exchange for Bonneville making available capacity during the preceding May 15 through October 14 period.

2(i) "NOB" means the points where the Pacific Northwest-Pacific Southwest DC Intertie transmission lines cross the Nevada-Oregon border.

2(j) "Partial Outage" means either (i) an interruption or curtailment of deliveries due to a partial reduction of available DC Intertie transmission capacity due to physical limitations, or (ii) the physical transmission capacity of the DC Intertie is reduced to zero for a period of time which is less than 24-consecutive hours.

2(k) "Peaking Energy" means the energy associated with Bonneville's deliveries of capacity to Burbank during periods when this Agreement operates as an Exchange or capacity sale pursuant to Section 12.

2(l) "Peaking Replacement Energy" means an amount of energy which Burbank is obligated to deliver to Bonneville, which is equal to the amount of Peaking Energy.

2(m) "PNW Coordination Agreement" means the contract among Bonneville and Pacific Northwest (PNW) generating entities, providing for coordinated operation of resources, designated as Contract No. 14-03-48221, as amended or replaced.

2(n) "Supplemental Energy" means the energy Burbank is obligated to make available as a purchase option for Bonneville, pursuant to section 7.

2(o) "Total Incremental Cost" means incremental fuel cost, incremental operation and maintenance, generating unit start-up cost, transmission losses incurred by Burbank in delivering Supplemental Energy to the Point of Delivery, cost of purchased energy, third party wheeling charges, and any other incremental cost incurred by Burbank in supplying Supplemental Energy to Bonneville that would not otherwise have been incurred.

2(p) "Total Outage" means the physical transmission capacity of the DC Intertie is reduced to zero, whether planned or unplanned, for a period of time which equals or exceeds 24-consecutive hours.

2(q) "UIC" means any unrecoverable incremental costs beyond normal operations incurred by Burbank in generating or acquiring Supplemental Energy for which Bonneville rescinds its request pursuant to paragraph 7(c)(3). UIC includes, but is not limited to, direct costs, penalties, cancellation fees for fuel commitments, transmission services, or unrecoverable energy purchases, but excludes general engineering, scheduling, and administrative charges. UIC shall not include costs incurred by Burbank to the extent that Burbank is able to make use of such Supplemental Energy and in doing so mitigates costs it has incurred or avoids costs it would otherwise have incurred.

2(r) "Workday" means each day which both Bonneville and Burbank observe as a regular workday.

3. Exhibits.

Bonneville Wholesale Power Rate Schedules and General Rate Schedule Provisions (Exhibit A), General Contract Provisions (Form PSC (SW-1)) (Exhibit B), Plan of Delivery (Exhibit C), Minimum Monthly Energy Distribution Tables for Burbank (Exhibit D), and Operating Procedures (Exhibit E) are attached hereto and hereby made a part of this Agreement.

4. Option for Burbank to Increase Purchase.

Not later than June 1, 1988, Burbank, Glendale, and Pasadena may, upon written notice, increase their power purchase by a total of 60 MW, or more, if Bonneville determines power is available for this purpose. To the extent that any such increase results in an increase for Burbank pursuant to this Agreement, then that increase shall become effective for the Contract Year beginning at 2400 hours on June 30, 1988, and shall be distributed equally to Blocks 1 and 2 for both the surplus firm power sale and Exchange under this Agreement. This Agreement shall be amended as necessary to reflect such increase.

5. Surplus Firm Power Sale.

5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Burbank shall purchase 17,939 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Burbank shall purchase during each Contract Year 43,362 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Burbank shall purchase during each Contract Year while this Agreement remains a power sale, 47,304 MWh of surplus firm energy.

5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Burbank shall purchase 16,524 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing until 2400 hours on June 30, 1992, Burbank shall purchase 5,076 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, and continuing until 2400 hours on October 14, 1992, Burbank shall purchase 12,593 MWh of surplus firm energy. Beginning at 2400 hours on May 14, 1993, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Burbank shall purchase 18,176 MWh of surplus firm energy.

5(c) Adjustments to Amount of Power.

The above MWh quantities for Burbank shall be adjusted as necessary to account for any increase pursuant to section 4. However, in the event of a partial Contract Year power sale for Block 1, or in the event of a partial May 15 through October 14 power sale for Block 2, Burbank shall purchase the appropriate monthly amounts of surplus firm energy under Block 1 and under Block 2 as shown in the applicable plan of delivery for such Contract Year pursuant to subsection 5(e). Burbank may increase the energy scheduled for purchase from Bonneville for any month under the then-current plan of delivery, if such energy is available as determined by Bonneville for such purpose. Such increases shall not affect the plan of delivery, the minimum monthly energy delivery in any future months during such Contract Year, nor shall any such increase affect the take-or-pay energy amount in any future Contract Year.

5(d) Rates of Delivery.

The maximum hourly rates of delivery for surplus firm power shall be 9 MW from October 15 through May 14 and 18 MW from May 15 through October 14, as may be modified by Burbank's option to increase pursuant to section 4.

5(e) Distribution of Monthly Amounts.

Prior to January 1 of each year, Burbank shall submit a plan of delivery to Bonneville showing the distribution of the monthly amounts of energy for the following 4 Contract Years in the form represented by Exhibit C. Burbank shall distribute the monthly amounts of energy within the limits indicated in Exhibit D.

5(e)(1) If requested by Burbank, Bonneville shall consult with Burbank at the time such plans of delivery are being prepared. Bonneville will share its most recent information on its ability to serve Burbank with a power sale for the following 4 Contract Years and any other

considerations that may relate to the plans of delivery. Bonneville shall include such plans of delivery in its PNW Coordination Agreement planning.

5(e)(2) The Parties shall rely upon the most recent plan of delivery submitted to Bonneville for the amount of energy to be delivered in the upcoming July. Bonneville shall notify Burbank at the earliest opportunity, but not later than August 15, if other than that most recent proposed plan of delivery shall become effective for the balance of the Contract Year. Unless otherwise agreed by the Parties, notwithstanding the limits indicated in Exhibit D, the total of the monthly amounts Bonneville shall deliver during July and August shall equal the 2-month July and August total energy amount specified in the plan of delivery ultimately adopted for use during that Contract Year; provided, however, that in the event that Burbank is unable to receive the minimum amount of energy during August due to the timing of such notice, then the Parties shall adjust deliveries as necessary prior to November 16 to provide for any energy not received during August.

5(e)(3) If Bonneville adopts a plan of delivery other than the most recent plan of delivery submitted, Bonneville shall adjust the adopted plan of delivery to reflect the most recent Intermountain Power Project scheduled maintenance outages.

5(f) Distribution of Weekly Amounts.

Within any month, Burbank shall not take more than 135 percent of that month's average weekly amount in any Calendar Week. Such average weekly amount shall be equal to the total MWh for that month as specified in the applicable plan of delivery, divided by the number of days in that month, and multiplied by 7.

5(g) Operational Flexibility.

Burbank may request changes of up to 5 percent of any monthly amount of energy to be made available under the Agreement, with no less than 2 months' advance written notice. Such changes shall not be unreasonably denied by Bonneville, and the ability to make such changes shall be at no additional cost to Burbank. The effect of such changed monthly amount on subsequent monthly amounts of energy shall be included in this notice; provided, however, that changes in monthly amounts purchased hereunder shall not be reduced below the minimum monthly amounts of energy specified in Exhibit D, unless mutually agreed to by the Parties.

6. Conversion to the Exchange.

The sale of surplus firm power shall convert to the Exchange if Bonneville has a surplus firm energy insufficiency under the

conditions described in this section; provided, however, that Burbank shall have the option to either: (i) remain in the power sale mode until after other similar long term sale and exchange agreements executed with parties outside of the Pacific Northwest region for which initial deliveries shall commence after January 1, 1988, have been converted to an exchange; or (ii) convert to the Exchange prior to the conversion of such other similar long term sale and exchange agreements. Burbank shall exercise its option within 14 days after Burbank receives Bonneville's written notice that it will be converting this Agreement or such other similar agreements to an exchange.

6(a) Preliminary Notice.

6(a)(1) If Bonneville determines in the PNW Coordination Agreement planning process that there is a possibility of insufficient surplus firm energy to satisfy the surplus firm energy obligation to Burbank in the next Contract Year, Bonneville shall provide written notice to Burbank as soon as possible. Following this notice, the Parties may, upon mutual agreement, begin the Exchange at 2400 hours on May 14 or on a subsequent date prior to 2400 hours on June 30 of the then-current Contract Year.

6(a)(2) If Bonneville determines in the planning process that there is a certainty of insufficient surplus firm energy for the next Contract Year, Bonneville shall provide written notice to Burbank as soon as possible, but not later than June 15. In this event, regardless of the extent to which PNW system refill occurs, the Exchange shall begin at 2400 hours on June 30. Burbank's Exchange Energy obligation for Block 2 shall be adjusted to account for a start date of July 1 rather than May 15.

6(b) Final Notice.

If the Exchange does not begin pursuant to subsection 6(a), then the provisions of this subsection apply. The completion of PNW Coordination Agreement planning and the adoption by Bonneville of a particular plan of delivery for Burbank shall occur after July 31. Bonneville shall provide written notice to Burbank as soon as possible after July 31, but not later than August 15, whether service at the Contract Demand shall continue as a power sale or convert to the Exchange. If such notice specifies a conversion to the Exchange, then the Exchange shall begin no sooner than 14 days after the date of receipt of such notice by Burbank. Conversion to the Exchange shall be effective for the remainder of the Contract Year from the time specified in Bonneville's notice to Burbank, or as provided for in subsection 6(c). Burbank's Exchange Energy obligation shall be adjusted to account for the start date specified in the notice rather than May 15.

6(c) Reversion to Power Sale.

After conversion to the Exchange, whenever Bonneville determines that it has sufficient surplus firm energy to deliver the amounts of surplus firm power specified in subsections 5(a) and 5(b) for the ensuing Contract Year, deliveries under this Agreement shall revert to the surplus firm power sale pursuant to section 5, unless Burbank has provided written notice to Bonneville which describes a contract offer to acquire a resource to replace the energy no longer available from Bonneville due to the conversion to the Exchange. Such notice shall include the amount of energy to be acquired and the term of the proposed acquisition. Bonneville shall respond as follows:

Bonneville shall, within 21 days of receipt of such notice, notify Burbank as to whether this transaction shall revert to the power sale for the duration of Burbank's proposed energy acquisition. If this transaction is to revert to the power sale, Bonneville shall notify Burbank of the basis for the reversion, and such power sale shall begin by the later of (1) 31 days from receipt by Bonneville of Burbank's notice, or (2) the effective date of energy deliveries pursuant to Burbank's proposed acquisition, and shall continue for the duration of Burbank's acquisition, subject to the provisions of section 12. If Bonneville elects not to have the transaction revert to the power sale, then Bonneville shall waive its right to revert to the power sale for the duration of Burbank's contractual commitment for the proposed energy acquisition. Prior to the termination of Burbank's acquisition contract, Bonneville shall, upon written notice of at least 30 days, have the right to revert to the power sale as described in section 5 at the termination of Burbank's acquisition.

6(d) The notice provisions of subsections 6(a) and 6(b) shall apply to reversion from Exchange to power sale, as well as the conversion from power sale to Exchange, except as may be modified by the provisions of subsection 6(c).

7. Capacity For Energy Exchange.

Upon conversion to the Exchange, Bonneville shall make 9 MW of capacity available to Burbank for Block 1 on an annual basis and 9 MW of capacity for Block 2 from May 15 through October 14 each year, as may be modified by Burbank's option to increase pursuant to section 4. Burbank shall be obligated to deliver Peaking Replacement Energy to Bonneville during these periods of capacity deliveries as specified in subsection 7(a). In Exchange for Bonneville deliveries of capacity, Burbank shall deliver Exchange Energy and make available Supplemental Energy to Bonneville, as specified in subsections 7(b) and 7(c).

7(a) Deliveries of Capacity and Peaking Replacement Energy.

At times when the Exchange is in effect, Bonneville shall make available to Burbank capacity in an amount up to the Contract Demand each hour, up to 10 hours times the Contract Demand each day Monday through Saturday, including holidays, not to exceed 50 hours times the Contract Demand each week. Burbank shall be obligated to deliver to Bonneville Peaking Replacement Energy for the amounts of Peaking Energy delivered to Burbank by 2400 hours on the day following the Peaking Energy delivery, except as provided in subsection 7(e). Return of Peaking Replacement Energy during any hour shall not exceed 100 percent of the Contract Demand in any hour, unless otherwise mutually agreed by the parties.

7(b) Exchange Energy.

Burbank shall be obligated to deliver Exchange Energy to Bonneville as provided herein. The amount of such energy provided each Contract Year shall equal the exchange ratio in kWh/kW for each block of capacity, multiplied by the Contract Demand in kilowatts for each block of capacity. For Block 1, the exchange ratio is 2,536 kWh/kW; for Block 2, the exchange ratio is 975 kWh/kW. Exchange Energy for Block 1 shall be delivered in equal weekly increments throughout the year and Exchange Energy for Block 2 shall be delivered in equal weekly increments from November 16 through April 15, except as provided in subsection 7(e). Such equal weekly increments shall be adjusted as necessary to account for an uneven number of weeks during any Exchange Energy delivery period. In the event of a partial Contract Year of capacity deliveries, the amount of Exchange Energy which Burbank is obligated to deliver to Bonneville shall be reduced on a pro rata basis to account for such partial Contract Year.

7(c) Supplemental Energy.

7(c)(1) Burbank shall be obligated to make Supplemental Energy available to Bonneville during each November 16 through April 15 while this Agreement operates as an Exchange. The total amount of such energy provided each Contract Year shall equal the supplemental ratio in kWh/kW multiplied by the Block 2 Contract Demand in kilowatts of capacity. The supplemental ratio is 1,200 kWh/kW. Bonneville may elect to purchase up to the maximum amount of Supplemental Energy available to Bonneville in any Contract Year by serving a notice to Burbank not less than 2 months prior to the desired delivery date, or on shorter notice if agreed to by Burbank. Bonneville may issue additional notices during any Contract Year for amounts of Supplemental Energy not previously requested in a notice. Any such notice shall specify the amount of Supplemental Energy desired by Bonneville and provide a

nonbinding proposed schedule for deliveries of Supplemental Energy. Burbank shall promptly notify Bonneville if such proposed schedule is unacceptable to Burbank and the reasons therefor. Burbank shall not unreasonably deny Bonneville's proposed schedule. In the event that the Parties are unable to agree on a proposed schedule, then the requested Supplemental Energy shall be delivered in equal hourly increments during the delivery period specified in Bonneville's notice and during the hours specified in paragraph 7(d)(3). Bonneville and Burbank shall finalize the schedule for deliveries of weekly blocks of Supplemental Energy within 15 Workdays of receipt by Burbank of Bonneville's notice. Deliveries of Supplemental Energy are subject to Burbank's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Burbank's generation or transmission capability. In the event of any such constraints, Burbank shall reschedule such deliveries in a timely manner. In the event of an extended generation constraint, Bonneville may request an alternate available source for Supplemental Energy at another agreed upon price, until such time as the generation constraint is removed.

7(c)(2) Within 15 Workdays of receipt of Bonneville's notice requesting to make available Supplemental Energy, and prior to committing to obtain Supplemental Energy, Burbank shall inform Bonneville of probable resources available, including the estimated price of the lowest cost sources of Supplemental Energy available for purchase, the estimated Total Incremental Cost from such sources, and the UIC for such resources. Burbank shall revise such estimated price, Total Incremental Cost, and UIC if conditions change substantially during the remaining days of the notice period described in paragraph 7(c)(1). If Burbank determines that the UIC from such sources will exceed 4.5 mills, as escalated pursuant to subsection 9(c), it shall notify Bonneville, and Bonneville shall have the option of either: (1) raising such maximum rate for UIC; (2) relieving Burbank of its obligation to provide Supplemental Energy; or (3) obligating itself to purchase Supplemental Energy. Bonneville shall make this choice in a timely manner. Burbank shall use best efforts to mitigate UIC, but unless earlier notification by Burbank and Bonneville's selection of its option to raise the maximum rate for UIC has occurred, Bonneville's obligation for the amount of energy specified in its notice of rescission shall not exceed 4.5 mills/kWh as escalated pursuant to subsection 9(c).

7(c)(3) Bonneville shall pay Burbank any applicable Embedded Transmission Costs plus 115 percent of Burbank's Total Incremental Cost for providing Supplemental Energy. Bonneville may rescind a notice requesting Supplemental Energy not later than 0930 hours of the Workday immediately preceding the day when such Supplemental Energy was to begin to be provided to Bonneville, and pay Burbank any UIC incurred by Burbank in response to Bonneville's previous request for such energy. Any decision to rescind a notice requesting Supplemental Energy shall apply to the total amount of MWh of Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1); provided, however, that Bonneville can rescind a portion of the Supplemental Energy requested by Bonneville pursuant to paragraph 7(c)(1) if Bonneville agrees to pay any new UIC resulting therefrom.

7(c)(4) Bonneville shall submit schedules for the delivery of Supplemental Energy pursuant to the provisions of paragraph 7(c)(1) and section 10. Burbank shall not unreasonably withhold its agreement with such schedules, and Burbank shall deliver weekly amounts of Supplemental Energy by the end of each Calendar Week during the period of deliveries pursuant to the mutually agreed upon schedules for the delivery of Supplemental Energy.

7(d) Delivery Limitations.

7(d)(1) May 15 through October 14.

Unless limited by Bonneville, Burbank shall complete each Calendar Week's deliveries of Exchange Energy by the end of such Calendar Week. The maximum rate of delivery for Peaking Replacement Energy plus Exchange Energy shall be 100 percent of the Contract Demand. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account. Bonneville may limit the delivery rate for Peaking Replacement Energy plus Exchange Energy to not less than 60 percent of Contract Demand for the Exchange during the period May 15 through October 14. To the extent that Bonneville restricts the delivery on any hour, the restricted quantity of Peaking Replacement Energy and Exchange Energy may either be delivered by Burbank on hours other than the hours specified in paragraph 7(d)(3), or be delivered on the next available normal delivery hour when Bonneville can accept such energy. The Parties may agree to delay the delivery beyond the Calendar Week of delivery, or the Parties may agree to place such energy into the Energy Account, as described in paragraph 7(e)(1).

7(d)(2) November 16 through April 15.

Hourly rates of delivery shall be as mutually agreed upon by Bonneville and Burbank. However, during the period November 16 through April 15, during any hour the total rate of delivery for Exchange Energy plus Supplemental Energy plus Peaking Replacement Energy shall not exceed 250 percent of the Contract Demand, unless mutually agreed to by Bonneville and Burbank. Such maximum rate of delivery shall be in addition to any rate of delivery for energy being concurrently withdrawn from the Energy Account.

7(d)(3) Normal Delivery Hours for Peaking Replacement and Exchange Energy.

Although deliveries of Peaking Replacement Energy and Exchange Energy may occur during other hours, the normal delivery hours are as follows:

2200 hours on Monday to 0800 hours on Tuesday
2200 hours on Tuesday to 0800 hours on Wednesday
2200 hours on Wednesday to 0800 hours on Thursday
2200 hours on Thursday to 0800 hours on Friday
2200 hours on Friday to 0800 hours on Saturday
2200 hours on Saturday to 0800 hours on Monday.

7(e) Conditions for Energy Account and Cash-Out of Peaking Replacement and Exchange Energy.

7(e)(1) Declinations of Peaking Replacement Energy and Exchange Energy.

Bonneville may decline deliveries of either Peaking Replacement Energy or Exchange Energy in whole or in part. Bonneville shall provide Burbank with notice by 1400 hours on the Thursday prior to each Calendar Week. Such notice shall specify whether Bonneville will require the delivery of such energy in whole or in part for the next Calendar Week and shall specify the amount of energy which Bonneville declines. To the extent that Bonneville declines the deliveries, the monthly total of such declined energy and its value converted to mills/kWh pursuant to paragraph 7(e)(4) shall be entered into the Energy Account.

7(e)(2) Withdrawals from the Energy Account.

Bonneville may request to withdraw energy from the Energy Account during a Calendar Week and shall provide Burbank with notice by 1400 hours on the Thursday prior to such Calendar Week. Such notice shall specify the quantity of

energy to be withdrawn and the rate of delivery for such energy. However, in addition to other deliveries by Burbank pursuant to this Agreement, the maximum rate of withdrawal from the Energy Account shall not exceed the Contract Demand on any hour, unless mutually agreed. Burbank shall provide such requested energy to Bonneville during the next Calendar Week, subject to Burbank's generation and transmission constraints. Such constraints shall be limited to physical limitations resulting from an unplanned partial or total reduction of Burbank's generation or transmission capability. The value for energy withdrawn from the Energy Account shall be converted to kWh as determined pursuant to paragraph 7(e)(4) and shall be withdrawn on a first-in-first-out basis. To the extent that the value for withdrawn energy is greater than the value for declined energy determined pursuant to paragraph 7(e)(1), Bonneville shall pay Burbank an amount equal to the difference between the values for withdrawn and declined energy multiplied by the kWh withdrawn. To the extent that the value for withdrawn energy is less than the value for declined energy determined pursuant to paragraph 7(e)(1), Burbank shall pay Bonneville an amount equal to the difference between the values for declined and withdrawn energy multiplied by the kWh withdrawn. Each party shall pay the other pursuant to the provisions of section 8. If mutually agreed, withdrawn energy may be provided on hours other than those specified in paragraph 7(d)(3).

7(e)(3) Cash-Out of Energy in the Energy Account.

Bonneville shall maintain the Energy Account. The Energy Account shall contain monthly totals of (i) the declined energy remaining at the end of each calendar month, and (ii) the value of such energy converted to mills/kWh pursuant to paragraph 7(e)(4). Any monthly total of energy which remains in the Energy Account longer than 11 months shall be cashed out pursuant to subsection 9(b) at the cash-out price at the time the energy was entered into the Energy Account. No more than one monthly total of energy shall be cashed out on any monthly bill rendered to Burbank. Burbank shall pay Bonneville pursuant to the cash-out terms specified in subsection 9(b), and shall be relieved of any obligation thereafter to provide such monthly total of energy to Bonneville.

7(e)(4) Determination of Value for Energy Entered into Energy Account and Withdrawn from Energy Account.

Following receipt of its gas bill each month, Burbank shall provide Bonneville with a copy of a portion of such

bill which shows the dollars per dekatherm paid by Burbank for the total of all gas purchases for that month. Bonneville shall convert this amount to dollars per Btu and apply this ratio to an agreed-upon heat rate of 10,000 Btu per kWh to determine the value in mills per kWh for entries into and withdrawals from the Energy Account during the following month. To the extent that gas is not available or is no longer a significant fuel source for generation by Burbank, the Parties shall negotiate: (i) an alternate significant fuel source which is used by Burbank for generation; and (ii) a methodology to derive a value in mills/kWh for entries into and withdrawals from the Energy Account. This Agreement shall be amended to implement the results of such negotiation.

7(f) At Burbank's request, the Parties agree to negotiate in good faith mutually agreeable terms and conditions which would allow Burbank to deliver energy to Bonneville's system for later use by Burbank.

8. Payment.

8(a) Payment by Burbank.

Bonneville shall render preliminary and final adjusted monthly bills to Burbank. Burbank shall pay Bonneville by the close of business on the twentieth (20th) day after the date of each such preliminary bill and any adjustments that may occur on the final monthly bill. The date of such bills shall be no earlier than the mailing date of such bills. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Burbank, then the due date shall be the next following business day. Other provisions related to payment of bills shall be in accordance with the General Rate Schedule Provisions attached to this Agreement.

8(b) Payment by Bonneville.

Burbank shall render monthly bills to Bonneville. Bonneville shall pay Burbank by close of business on the twentieth (20th) day after the date of the bill. The date of such bill shall be no earlier than the mailing date of such bill. Should the twentieth (20th) day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day. Other provisions relating to payment of bills shall be in accordance with the General Rate Schedule provisions attached to this Agreement.

9. Rates and Cash-Out.

9(a) Surplus Firm Power.

9(a)(1) Initial Demand and Energy Rates.

The initial demand and energy rates for deliveries of power under Block 1 and Block 2 are as follows: $4.60/kilowatt-month (kW-mo.) and 20.5 mills/kWh (includes Intertie adder). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery.

9(a)(2) Rate Adjustment During First 5 Years.

The initial demand and energy rates for the period January 1, 1988, through December 31, 1988, are described in paragraph 9(a)(1). For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. The energy rates specified in this paragraph 9(a)(2) include the Intertie adder. The rates for calendar years 1989 through 1992 are as follows:

Calendar Year	Capacity ($/kW-mo.)	Energy (mills/kWh)
1989	4.88	21.73
1990	5.17	23.03
1991	5.48	24.42
1992	5.81	25.88

Subsequent to December 31, 1992, the demand and energy rates shall be adjusted pursuant to paragraph 9(a)(3).

9(a)(3) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

Adjustments under this paragraph begin January 1, 1993. For May and October, the demand charge for Block 2 shall be adjusted on a pro rata basis to account for the partial month of delivery. On the effective date of any Bonneville Priority Firm Power (PF) rate adjustment thereafter, the rate for surplus firm power (SL_{new}) shall be adjusted as follows:

$$SL_{new} = SL_n * \frac{PF_{new}}{PF_{prev}}$$

where SL_{new} = The effective surplus firm power demand and energy charges hereunder as adjusted to reflect the change between PF_{new} and PF_{prev}.

SL_n = For the initial adjustment under this paragraph 9(a)(3) the SL_n demand charge

shall be $5.81/kW-mo. and the energy charge shall be 25.88 mills/kWh. For all subsequent adjustments under this paragraph, the values for SL_n shall be the then-current values for the previous SL_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh, in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(b) Cash-out.

Bonneville shall cash out energy pursuant to paragraph 7(e)(3). Burbank shall pay Bonneville for such energy as provided below.

9(b)(1) Initial Cash-out.

The initial level for cash-out shall be 14.9 mills/kWh.

9(b)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any PF rate adjustment after the effective date of this Agreement, the level of the cash-out rate (CO_{new}) shall be adjusted as follows:

$$CO_{new} = CO_n * \frac{PF_{new}}{PF_{prev}}$$

where

CO_{new} = The effective level for cash-out as adjusted to reflect a new PF rate.

CO_n = For the initial adjustment under this paragraph 9(b)(2), CO_n shall be

14.9 mills/kWh. For all subsequent adjustments under this paragraph, the values for CO_n shall be the then-current values for the previous CO_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

9(c) Maximum Rate for UIC Incurred by Burbank if Bonneville Rescinds a Notice for Supplemental Energy.

9(c)(1) Initial Maximum Rate for UIC.

In accordance with subsection 7(c), the initial rate for UIC is 4.5 mills/kWh for the amount of energy specified in Bonneville's notice of rescission.

9(c)(2) Adjustment Resulting from Adoption of New Priority Firm Power Rate Schedules.

On the effective date of any Priority Firm Power (PF) rate adjustment after the effective date of this Agreement, the maximum rate for UIC (UIC_{new}) shall be adjusted as follows:

$$UIC_{new} = UIC_n * \frac{PF_{new}}{PF_{prev}}$$

where

UIC_{new} = The effective rate for UIC as adjusted to reflect a new PF rate.

UIC_n = For the initial adjustment under this paragraph 9(c)(2), UIC_n shall be equal to 4.5 mills/kWh. For all subsequent adjustments under this paragraph, the

values for UIC_n shall be the then-current values for the previous UIC_{new}.

PF_{new} = The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

PF_{prev} = The average PF rate or successor rate(s) in mills per kWh in effect during the previous rate period. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

10. Scheduling Provisions for Power Sale and Exchange.

Submission of all schedules between the Parties shall be subject to the following provisions unless otherwise agreed upon by the Parties' respective schedulers or dispatchers or their agents:

10(a) Preschedules shall be completed on each Workday. Preschedules shall be effective for each hour of the following day or days through the next Workday.

10(b) Prescheduled amounts shall be submitted by 0930 hours.

10(c) This subsection 10(c) shall apply only to the power sale portion of this transaction. If Burbank desires to schedule other than that month's average weekly amount of energy for such month in any Calendar Week, Burbank shall notify Bonneville by 1400 hours on the Monday preceding such Calendar Week. Burbank may revise such new weekly amount if Burbank notifies Bonneville by 1400 hours on the Thursday preceding such Calendar Week.

10(d) By 1200 hours on any Wednesday, Bonneville may request estimates of the amounts that Burbank anticipates it will schedule from Bonneville each day for the following 10 days. Burbank shall submit such estimates to Bonneville by 1200 hours on the first Workday following the request. Such estimates are for the purpose of information only and shall not obligate either Burbank or Bonneville to schedule such amounts.

10(e) The Parties shall endeavor to avoid requesting changes in schedules. Requests for changes in prescheduled amounts for any hour shall be only as mutually agreed. Normally such changes

shall be submitted no later than 30 minutes before the hour for which the change is to be effective.

11. Transmission Limitation.

In the event of an interruption of deliveries by either Party due to a DC Intertie outage, the following provisions shall apply.

11(a) Relief Remedies During Periods of Total Outage.

The Parties shall be relieved of obligations as follows.

11(a)(1) Conditions for Capacity Payment Relief.

The following conditions must be met each Contract Year for relief to be given as described in paragraph 11(a)(2): (i) the duration of a single Total Outage exceeds 360-consecutive hours, in which case relief is provided for the remainder of such Total Outage only; or (ii) the sum of all Total Outages for the Contract Year exceeds 720 hours, excluding Total Outages, if any, for which relief was given pursuant to item (i) above.

11(a)(2) Determination of Capacity Payment Relief.

For the duration of the Total Outages which occur subsequent to the occurrence of relief as described in paragraph 11(a)(1), Burbank shall receive a capacity credit in the form of a reduction in the demand rate per kW-mo. calculated by determining such duration of the Total Outage during the billing month, divided by the total number of hours in that month.

11(a)(3) Energy Payment Relief During Power Sale.

Without regard to the duration of a Total Outage, if Burbank is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Burbank shall be relieved of its obligation to pay for such amounts of energy. To the extent that Burbank is unable to receive energy during any month, the monthly minimum take-or-pay energy specified in the applicable plan of delivery shall be reduced by an amount of energy determined as follows: a ratio shall be calculated, the numerator being the number of hours of Total Outage during the month that Burbank is unable to receive energy, and the denominator being the total number of hours in that month. This ratio is then multiplied by the monthly energy specified in the applicable plan of delivery to determine such amount of energy. This amount of energy shall be subtracted from such monthly energy to determine the revised monthly

amount for that month. The total take-or-pay energy for Block 1, or Block 2 if applicable, as specified in Exhibit D, shall be reduced by the amount of energy as calculated above.

11(a)(4) Energy Payment Relief During Exchange.

11(a)(4)(A) For Total Outages which occur subsequent to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Burbank's obligation to deliver Peaking Replacement Energy owed to Bonneville for previous capacity delivered by Bonneville, and Supplemental Energy requested by Bonneville pursuant to subsection 7(c) remain. Burbank's obligation to deliver Exchange Energy associated with a Total Outage up to one year remains, but, at Bonneville's option, either: (i) Burbank shall deliver such energy to Bonneville subject to mutually agreed upon schedules following the end of the Total Outage and Bonneville shall pay Burbank's Total Incremental Cost for the first 3 months of such obligation and 115 percent of Burbank's Total Incremental Cost for the following 9 months; or (ii) Burbank shall be relieved of its obligation to deliver such energy.

11(a)(4)(B) For Total Outages which occur prior to the occurrence of the conditions for relief as described in paragraph 11(a)(1), Burbank shall reschedule deliveries of Peaking Replacement Energy, Exchange Energy, and Supplemental Energy which Burbank is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the Total Outage, or at other times as mutually agreed by the Parties.

11(b) Relief Remedies During Periods of Partial Outage.

11(b)(1) Relief Remedies During the Power Sale.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue deliveries under this Agreement. The Parties also shall curtail pro rata on an hourly basis all agreements executed on or before January 1, 1988, for firm energy or capacity based on reductions of available transmission capacity, and the Parties shall

afford this Agreement precedence in transmission over agreements executed after January 1, 1988 for firm energy or capacity. If Burbank is unable to receive any amounts of energy, Bonneville shall be relieved of its obligation to deliver and Burbank shall be relieved of its obligation to pay for such amounts of energy.

11(b)(2) Relief Remedies During the Exchange.

During the Exchange, or during any period of the power sale when Bonneville has restricted surplus firm energy deliveries pursuant to section 12 and is delivering capacity only, the following provisions shall apply.

The Parties shall curtail nonfirm energy transactions pursuant to other agreements to the extent necessary to continue or reschedule deliveries under this Agreement. The Parties shall curtail all agreements for firm capacity without energy or deliveries of exchange energy executed prior to January 1, 1988, pro rata on an hourly basis, based on reductions of available transmission capacity, and the Parties shall afford this Agreement precedence in transmission over deliveries of capacity or exchange energy pursuant to agreements executed after January 1, 1988. Burbank shall reschedule interrupted or curtailed deliveries of Peaking Replacement Energy, Exchange Energy and Supplemental Energy which Burbank is obligated to provide to Bonneville, under conditions approximately equivalent to the conditions existing prior to the interruption or curtailment, or at other times and under conditions as mutually agreed by the Parties.

12. Restriction of Deliveries.

All sales under this Agreement are subject to the provisions of 16 U.S.C. § 837 (1984) (P.L. 88-552), and the Parties hereby acknowledge their respective responsibilities thereunder. Pursuant to those provisions, Bonneville shall have the right to restrict all or a portion of the capacity or energy if such capacity or energy is needed to meet the capacity or energy requirements, as the case may be, in the PNW. Such restrictions shall be limited in amounts and duration to cover the projected need specified in the written notice which Bonneville shall provide to Burbank. Such written notice shall specify the date on which a period of restriction begins and the date on which such period of restriction is projected to end. The sale of surplus firm power shall resume pursuant to the applicable plan of delivery for the remainder of the then-current Contract Year after expiration of the period of restriction except as described in the immediately following sentence. If a projected period of restriction exceeds 2 months' duration, Burbank may make other arrangements for energy for the remainder of such Contract Year if Burbank has entered into a contractual commitment with a third party as a direct result of Bonneville's prior notice of restriction, and Bonneville has received Burbank's written notice of such arrangements not later than 10 days prior to the projected end of such period of restriction.

During any period that Bonneville continues to have surplus firm energy on a planning basis, but Bonneville restricts the delivery of energy as provided above, Bonneville shall make available capacity at the Contract Demand and, in the event of a partial energy restriction, a pro rata amount of energy. Prior to the effective date of the restriction, Burbank shall give notice to Bonneville of the amount of capacity made available by Bonneville that Burbank desires for the anticipated duration of the restriction. In such notice, Burbank may reduce the amount of capacity it desires for the anticipated period of restriction below the Contract Demand, with no change in the rate per kW-mo. of capacity specified in section 9; provided, however, that if Burbank reduces the amount of capacity it desires during a period of restriction to zero, and the reduction to zero capacity occurs on any day other than the last day of a month, then Bonneville shall make a pro rata reduction in the rate per kW-mo. of capacity. Terms for the delivery of such capacity and for the cash-out or delivery of Peaking Replacement Energy shall be as provided in this Agreement.

13. Points of Delivery.

13(a) Points of Delivery.

The point of delivery for all deliveries to Bonneville pursuant to this Agreement is NOB.

13(b) Other Pacific Southwest Points of Delivery.

Notwithstanding the point of delivery specified in subsection 13(a), at Bonneville's request, Burbank shall deliver energy owed Bonneville to Pacific Southwest points of delivery where Burbank has interconnections and available transmission capacity with Pacific Southwest utilities.

13(c) Costs Incurred to Point of Delivery.

Each Party shall bear its own costs for deliveries to the point of delivery under subsections 13(a) and 13(b); provided, however, that all deliveries of Supplemental Energy by Burbank to Bonneville pursuant to subsection 7(c) shall be excluded from the provisions of this subsection.

14. Limit of Liability.

It is mutually understood and agreed that Burbank's obligations for the payment of monies pursuant to this Agreement are limited to revenues received by Burbank from the sale of electric power and/or

the disposition of assets of Burbank's power generation and transmission facilities.

IN WITNESS WHEREOF, the Parties have executed this Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ James J. Jura
Administrator

Date January 28, 1988

CITY OF BURBANK, CALIFORNIA

By /s/ Alan E. Capon

Title Acting General Manager

Date December 14, 1987

APPROVED AS TO FORM
CITY ATTORNEY
Date 12-7-87
By /s/ Richard W. Marston
Title Sr. Assist. City Atty.

PLAN OF DELIVERY

1. Monthly Amounts of Energy Requested by Burbank Pursuant to Subsection 5(e).

Year / Month	1988	1989	1990	1991
July				
August				
September				
October				
November				
December				
January				
February				
March				
April				
May				
June				

This attachment will be revised each year upon Burbank's submission of new data.

2. Example, assuming 1992 Power Sale.

Upon Burbank's submittal of plans of delivery each year in accordance with subsection 5(e), Bonneville shall use such plans in its PNW Coordination Agreement planning. That is, the information from such submittals shall be included in initial, modified, and final coordinated system regulations. Assuming energy sufficient to serve Burbank load as a power sale, the plan of delivery to be used is based upon the degree to which the coordinated system refills.

At 2400 hours on July 31, 1992, or shortly thereafter, parties to the PNW Coordination Agreement determine reservoir elevations corresponding to the level of refill. If the system refills, Bonneville will implement the most recent plan of delivery submitted by Burbank. If the system does not refill, such parties will use the system capability associated with actual elevations to most closely match planning done in previous years (earlier "Critical Periods"). This can be shown as follows:

Critical Period	Burbank's Plan of Delivery
1992 - 1995 (refill)	year 1992 from 1992 submittal
1991 - 1994	year 1992 from 1991 submittal
1990 - 1993	year 1992 from 1990 submittal
1989 - 1992	year 1992 from 1989 submittal

If less than a 4 year Critical Period is ever used, there may be fewer than 4 alternatives to be considered.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 9 MW DEMAND		BLOCK 2: 9 MW DEMAND		TOTAL MWh
	LF =	MIN. MWh	LF =	MIN. MWh	
J	30% =	2,009			2,009
F	30% =	1,814			1,814
M	40% =	2,678			2,678
A	50% =	3,240			3,240
M	55% =	3,683	May (15-31) 50% =	1,836	5,519
J	55% =	3,564	50% =	3,240	6,804
J	65% =	4,352 1/	50% =	3,348 1/	7,700
A	65% =	4,352 1/	55% =	3,683 1/	8,035 2/
S	65% =	4,212	50% =	3,240	7,452
O	50% =	3,348	Oct. (1-14) 15% =	454	3,802
N	30% =	1,944			1,944
D	30% =	2,009			2,009
TOTAL		37,205		15,801	
TAKE-OR-PAY		43,362 3/		16,524 3/	
BLOCK 1 LF = 55%			BLOCK 2 LF = 50%		

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).
3/ These figures will be increased on July 1, 1992, pursuant to page 2 of this Exhibit D.

(WP-PKLD-3463c)

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 9 MW DEMAND			BLOCK 2: 9 MW DEMAND			TOTAL MWh
	LF	=	MIN. MWh	LF	=	MIN. MWh	
J	30%	=	2,009				2,009
F	30%	=	1,814				1,814
M	40%	=	2,678				2,678
A	50%	=	3,240				3,240
M	55%	=	3,683	May (15-31) 50%	=	1,836	5,519
J	55%	=	3,564	50%	=	3,240	6,804
J	65%	=	4,352 1/	50%	=	3,348 1/	7,700
A	65%	=	4,352 1/	55%	=	3,683 1/	8,035 2/
S	65%	=	4,212	50%	=	3,240	7,452
O	50%	=	3,348	Oct. (1-14) 15%	=	454	3,802
N	30%	=	1,944				1,944
D	30%	=	2,009				2,009
TOTAL			37,205			15,801	
TAKE-OR-PAY			47,304			18,176	
BLOCK 1 LF = 60%				BLOCK 2 LF = 55%			

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(c)(2).

(WP-PKLD-3463c)

OPERATING PROCEDURES

No operating procedures have been established as of the date of execution of this Agreement.

Prior to conversion to the Exchange, the Parties agree to develop operating procedures which shall be utilized during the Exchange. Such procedures shall include, but are not limited to, determination and verification of Total Incremental Cost, determination and verification of UIC, operating procedures under the Energy Account, and operating procedures during periods of Total Outage and Partial Outage.

These procedures shall be inserted into this Exhibit and shall in no way alter the substance or intent of any language contained in this Agreement.

AUTHENTICATED COPY

Amendatory Agreement No.1
Contract No. DE-MS79-87BP92411

June 14, 1988

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF BURBANK

This AMENDATORY AGREEMENT, executed as of July 6, 1988, by the UNITED STATES OF AMERICA (the Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and THE CITY OF BURBANK, CALIFORNIA (Burbank), a municipal corporation organized and existing under the laws of the State of California, hereinafter sometimes referred to individually as "Party" and collectively as "Parties";

W I T N E S S E T H:

WHEREAS Bonneville is engaged in the sale of electric capacity and energy at wholesale, and is projecting availability of amounts in excess of its existing firm obligations to deliver such capacity and energy; and

WHEREAS Burbank is a municipal corporation engaged in the generation, transmission, and distribution of electric energy in California; and

WHEREAS on January 28, 1988, Burbank and Bonneville executed Contract No. DE-MS79-87BP92411 (Sale and Exchange Agreement), which provides, among other things, for Bonneville to sell surplus firm capacity with energy to Burbank; and

WHEREAS the Sale and Exchange Agreement also provides that Bonneville and Burbank shall enter into an annual and seasonal capacity for energy exchange at such time as Bonneville determines it is unable to continue the sale of surplus firm capacity with energy; and

WHEREAS in accordance with the provisions of section 4 of the Sale and Exchange Agreement, Burbank has exercised its option to increase the power purchase from 9 MW for Block 1 and 9 MW for Block 2 to 20 MW for Block 1 and 20 MW for Block 2; and

WHEREAS Burbank has requested and Bonneville has agreed that at such time as the power sale converts to an annual and seasonal capacity for energy exchange, the capacity amounts made available by Bonneville will remain at 9 MW for Block 1 and 9 MW for Block 2; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric capacity and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate

transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto agree as follows:

1. Effective Date of Amendatory Agreement.

This Amendatory Agreement, when executed, shall become effective at 2400 hours on June 30, 1988.

2. Amendment of Sale and Exchange Agreement.

The Sale and Exchange Agreement, Contract No. DE-MS79-87BP92411, is hereby amended as follows:

(a) Section 4 is deleted and replaced by a new section 4 as follows:

"4. Increase in Power Purchase for Burbank.

Burbank, by letter to Bonneville dated May 20, 1988, elected to increase its power purchase under the Sale and Exchange Agreement from 9 MW for Block 1 and 9 MW for Block 2 to 20 MW for Block 1 and 20 MW for Block 2. Notwithstanding such increase in the power purchase, the capacity amounts made available by

Bonneville under the Exchange shall remain at 9 MW for Block 1 and 9 MW for Block 2.

(b) Subsection 5(a) is deleted and replaced by the following:

"5(a) Amounts of Power Under the Annual Sale (Block 1).

Beginning at 2400 hours on January 31, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Burbank shall purchase 17,939 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on June 30, 1992, Bonneville shall make available and Burbank shall purchase during each Contract Year 96,360 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1992, Bonneville shall make available, and Burbank shall purchase during each Contract Year while this Agreement remains a power sale, 105,120 MWh of surplus firm energy."

(c) Subsection 5(b) is deleted and replaced by the following:

"5(b) Amounts of Power During the May 15 through October 14 Period (Block 2).

Beginning at 2400 hours on May 14, 1988, and continuing until 2400 hours on June 30, 1988, Bonneville shall make available and Burbank shall purchase 4,588 MWh of surplus firm energy. Beginning at 2400 hours on June 30, 1988, and continuing until 2400 hours on October 14, 1988, Bonneville shall make available and Burbank shall purchase 26,525 MWh of surplus firm energy.

Beginning at 2400 hours on May 14, 1989, and continuing until 2400 hours on October 14, 1991, Bonneville shall make available and Burbank shall purchase 36,720 MWh of surplus firm energy during each May 15 through October 14 period. Beginning at 2400 hours on May 14, 1992, and continuing for each May 15 through October 14 period while this Agreement remains a power sale, Burbank shall purchase 40,392 MWh of surplus firm energy."

(d) Exhibit D, which was effective at 2400 hours on January 31, 1988, is deleted and replaced by the attached Exhibit D.

3. Signature Clause The signatories hereto represent that they have been appropriately authorized to enter this Amendatory Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have executed this Amendatory Agreement.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ Jack Robertson
ACTING Administrator
JUN 29 1988
Date

CITY OF BURBANK, CALIFORNIA

By /s/ Ronald V. Stassi

Title General Manager. P.S.D.

Date July 6, 1988

(VS6-PMC-3732c)

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 20 MW DEMAND		BLOCK 2: 20 MW DEMAND			TOTAL MWh
	LF =	MIN. MWh		LF =	MIN. MWh	
J	30% =	4,464				4,464
F	30% =	4,032				4,032
M	40% =	5,952				5,952
A	50% =	7,200				7,200
M	55% =	8,184	May (15-31)	50% =	4,080	12,264
J	55% =	7,920		50% =	7,200	15,120
J	65% =	9,672 1/		50% =	7,440 1/	17,112
A	65% =	9,672 1/		55% =	8,184 1/	17,856 2/
S	65% =	9,360		50% =	7,200	16,560
O	50% =	7,440	Oct. (1-14)	15% =	1,008	8,448
N	30% =	4,320				4,320
D	30% =	4,464				4,464
TOTAL		82,680			35,112	
TAKE-OR-PAY		96,360 3/			36,720 3/	
BLOCK 1 LF = 55%				BLOCK 2 LF = 50%		

1/ July and August in both Blocks have maximum load factors of 75%.
2/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).
3/ These figures will be increased in 1992, pursuant to page 2 of this Exhibit D.

MINIMUM MONTHLY ENERGY DISTRIBUTION TABLE FOR BURBANK

	BLOCK 1: 1/ 20 MW DEMAND		BLOCK 2: 20 MW DEMAND		TOTAL MWh
	LF =	MIN. MWh	LF =	MIN. MWh	
J	30% =	4,464			4,464
F	30% =	4,032			4,032
M	40% =	5,952			5,952
A	50% =	7,200			7,200
M	55% =	8,184	May (15-31) 50% =	4,080	12,264
J	55% =	7,920	50% =	7,200	15,120
J	65% =	9,672 2/	50% =	7,440 2/	17,112
A	65% =	9,672 2/	55% =	8,184 2/	17,856 3/
S	65% =	9,360	50% =	7,200	16,560
O	50% =	7,440	Oct. (1-14) 15% =	1,008	8,448
N	30% =	4,320			4,320
D	30% =	4,464			4,464
TOTAL		82,680		35,112	
TAKE-OR-PAY		105,120		40,392	
BLOCK 1 LF = 60%			BLOCK 2 LF = 55%		

1/ The total take-or-pay energy amount for Block 1 shall be effective at 2400 hours on June 30, 1992.
2/ July and August in both Blocks have maximum load factors of 75%.
3/ Subject to adjustment pursuant to the provisions of paragraph 5(e)(2).

SERVICE AGREEMENT
for
POINT-TO-POINT
TRANSMISSION SERVICE
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
TRANSCANADA POWER
a division of
TRANSCANADA ENERGY ~~LIMITED~~ LTD. KJ
CP

1. This Service Agreement, dated as of **_Jan. 22nd/2002_**, is entered into, by and between the Bonneville Power Administration Transmission Business Line (Transmission Provider) and TransCanada Power, a division of TransCanada Energy Limited (Transmission Customer).

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point (PTP) Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff).

3. The Transmission Customer has provided to the Transmission Provider a deposit, if applicable, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.

4. Service under this agreement shall commence on 2400 hours on January 13, 2002, and shall terminate on 2400 hours on January 13, 2032.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit B.

7. The Tariff, Exhibit A (Specifications for Long-Term Firm Point-To-Point Transmission Service), and Exhibit B (Notices) are incorporated herein and made a part hereof. Capitalized terms not defined in this agreement are defined in the Tariff.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(i) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

TRANSCANADA POWER a division of TransCanada Energy ~~Limited~~ **Ltd. KJ**	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ KARL JOHANNSON**	By: **/S/ CLIFFORD C PERIGO**
Name: **Karl Johannson** *(Print/Type)*	Name: Clifford C. Perigo *(Print/Type)*
Title: **Vice President Western Power**	Title: Senior Transmission Account Executive
Date: **Jan. 22nd/2002**	Date:

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EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 1
REQUEST FOR TRANSMISSION SERVICES

Table 1 is not applicable at this time.

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TABLE 2
DIRECT ASSIGNMENT AND USE-OF-FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

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TABLE 3
ANCILLARY SERVICE CHARGES

This Table 3 is subject to the ACS-02 Rate Schedule or successor rate schedules.

		Provided By	Contract No.
1.	**SCHEDULING, SYSTEM CONTROL AND DISPATCH**	Transmission Provider	02TX-10882
2.	**REACTIVE SUPPLY AND VOLTAGE CONTROL**	Transmission Provider	02TX-10882
3.	**REGULATION & FREQUENCY RESPONSE**	As Applicable	02TX-10882
4.	**ENERGY IMBALANCE SERVICE**	As Applicable	02TX-10882
5.	**OPERATING RESERVE - SPINNING RESERVE**	As Applicable	02TX-10882
6.	**OPERATING RESERVE - SUPPLEMENTAL RESERVE**	As Applicable	02TX-10882

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EXHIBIT B
NOTICES

1. **NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT**
Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, First Class mail, by telefax or sent by acknowledged delivery.

If to the Transmission Customer:

TransCanada Power
450, 1st Street SW
Calgary, AB T2P 5H1
CANADA
Attention: Douglas Way
Title: Power Trader
Phone: (403) 920-5038
Fax: (403) 920-2464
E-Mail: doug_way@transcanada.com

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491
Attention: Senior Transmission Account Executive for TransCanada Power – TM/Ditt2
Phone: (360) 418-8293
Fax: (360) 418-8320

2. **NOTICES OF AN OPERATING NATURE**
Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by telefax or sent by First Class mail or acknowledged delivery.

If to the Transmission Customer:

TransCanada Power
450, 1st Street SW
Calgary, AB T2P 5H1
CANADA
Attention: Prescheduling
Phone: (403) 920-2904
Fax: (___) ___-_____

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491
Attention: Real-Time Scheduling
Phone: **EMERGENCY ONLY**
(360) 695-2650
Fax: (360) 418-8740

3. **SCHEDULING AGENT**
Not applicable at this time.

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 01 498160
REQUEST FOR TRANSMISSION SERVICES

1. TERM OF TRANSACTION

Start Date: at 0000 hours on December 1, 2004.

Termination Date: at 0000 hours on April 1, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent
TransCanada Energy Ltd.	John Day Substation (500 kV)	BPA	30,000	COB (500 kV)	BPA	30,000	CISO	TransCanada Energy Ltd.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation 500 kV	COB 500 kV	12/01/04 - 4/01/06: 30 MW	IS-02

4. DESCRIPTION OF POINTS OF INTERCONNECTION

John Day Substation:

Location: The points in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: quantities are to be scheduled

5. **POINTS OF DELIVERY**
California Oregon Border (COB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon Border, where BPA shall make Electric power available for the California Independent System Operator (CISO) hereunder.

Voltage: 500 kV

Metering: quantities are to be scheduled

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None

TRANSCANADA POWER a division of TransCanada Energy Ltd.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ KARL JOHANNSON Karl Johannson Vice President Western Power	By: /S/ CLIFFORD C PERIGO
Name: /S/ CARL CALATONE (Print/Type) Carl Calatone	Name: Clifford C. Perigo (Print/Type)
Title: V.P. Power Strategy	Title: Sr Act Exec.
Date: 3-11-03	Date: 2-20-03

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AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 01 498159
REQUEST FOR TRANSMISSION SERVICES

1. TERM OF TRANSACTION

Start Date: at 0000 hours on October 1, 2003.

Termination Date: at 0000 hours on April 1, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent
TransCanada Energy Ltd.	John Day Substation (500 kV)	BPA	20,000	COB (500 kV)	BPA	20,000	CISO	TransCanada Energy Ltd.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation 500 kV	COB 500 kV	10/01/03- 4/01/06: 20 MW	IS-02

4. DESCRIPTION OF POINTS OF INTERCONNECTION
John Day Substation:

Location: The points in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: quantities are to be scheduled

5. **POINTS OF DELIVERY**
California Oregon Border (COB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon Border, where BPA shall make Electric power available for the California Independent System Operator (CISO) hereunder.

Voltage: 500 kV

Metering: quantities are to be scheduled

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None

TRANSCANADA POWER a division of TransCanada Energy Ltd.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ Karl Johannson Karl Johannson Vice President Western Power	By: /S/ CLIFFORD C PERIGO
Name: /S/ Carl Calantone (Print/Type) Carl Calantone	Name: Clifford C Perigo (Print/Type)
Title: V. P. Power Strategy	Title: Sr. Act Exec
Date: 3-11-03	Date: 2-20-03

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SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
HERMISTON POWER PARTNERSHIP

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Exhibit A	(Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit B	(Facilities Charges)
Exhibit C	(Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 10th day of May1999, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and Hermiston Power Partnership (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 TERMS AND CONDITIONS

BPA agrees to provide and the Transmission Customer agrees to take and pay for PTP Transmission Services in accordance with the provisions of this Service Agreement and the Open Access Transmission Tariff (Tariff). The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference. BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory

or preferential. BPA and the Transmission Customer agree that Transmission Service provided pursuant to this Service Agreement may be provided under a Commission-approved successor tariff after September 30, 2001, if BPA supersedes the Tariff.

1.2 STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit A and made applicable to that transaction.

1.3 WHOLESALE POWER AND TRANSMISSION RATES SCHEDULES

BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated by this reference.

1.4 FACILITIES CHARGES

All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit B.

1.5 ANCILLARY SERVICES

The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit C.

1.6 TRANSMISSION SCHEDULING PROVISIONS

The Transmission Customer shall schedule transmission transactions in accordance with BPA's Transmission Scheduling Provisions and Procedures as posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPAT

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

This Service Agreement shall be effective on the date executed as written above. Service under this Service Agreement shall commence on the later of: (a) 2400 hours on July 1, 2001 or (b) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades is completed; provided, however, that service may not commence later than the maximum period allowed in the Tariff for extensions for commencement of service. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on June 30, 2021 or (b) 2400 hours on the date of termination established pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 CHARGES FOR TRANSMISSION SERVICE

The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the BPA Wholesale Power and Transmission Rate Schedules. BPA may change the rates that apply to Transmission Service under this Service Agreement pursuant to applicable law.

4.2 BILLING AND PAYMENT

Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and shall be payable in accordance with the Tariff.

4.3 BPA APPROPRIATIONS REFINANCING ACT, PUBLIC LAW 104-134

The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If to Hermiston Power Partnership:

Hermiston Power Partnership
3380 Americana Terrace, Suite 300
Boise, ID 83706
Attention: Mike Elliott, P.E.
Title: Project Manager
Phone: (208) 395-8930
Fax: (208)395-8931

If to BPA:

Bonneville Power Administration
P. O. Box 491
Vancouver, WA 98666-0491
Attention:
Transmission Account Executive for
Hermiston Power Partnership

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified Transmission Service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 INTERCONNECTION WITH OTHER SYSTEMS

Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 GOVERNING LAW

This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3 AMENDMENTS

Except as provided in Articles 1.1, 6.4, and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 TARIFF REVISIONS

In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than 60 days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within 30 days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within 30 days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the

Transmission Service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.5 REVISION OF EXHIBITS

If any changes to Exhibits A, B, or C are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.5.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit A pursuant to this Service Agreement, BPA shall prepare a revised Exhibit A. BPA reserves the unilateral right to amend contiguous point of delivery provisions in Exhibit A of this Service Agreement.

6.5.2 If the Parties agree to change Exhibit B, BPA shall prepare a new Exhibit B. BPA reserves the right to revise Exhibit B annually to reflect changes consistent with the provisions of Exhibit B, section 1.

6.5.3 If the Parties agree to change Exhibit C, BPA shall prepare a new Exhibit C. BPA reserves the right to update the loss factors identified in Exhibit C, section 2, Transmission Loss Factors.

6.6 TEMPORARY LOAD SHIFTS AND MAINTENANCE NOTIFICATION

The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within 4 days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The point of contact for each Party will be designated pursuant to Article 5.2 of this Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within 4 days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.7 SEVERABILITY

In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.8 COMPUTATION OF TIME

To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.9 NO THIRD PARTY BENEFICIARIES

This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.10 WAIVERS

Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.11 SUCCESSORS AND ASSIGNS

This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.12 SERVICE AGREEMENT GOVERNS

In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.13 RELATED AGREEMENTS

6.13.1 System Impact Study and Facilities Study Agreement, Contract No. 98TX-30145;

6.13.2 Construction Agreement, Contract No. 99TX-10238 (under negotiation as of 4/9/99).

6.13.3 Letter of Understanding, Contract No. 99TX-10196 (offered 4/1/99).

6.13.4 Interconnection Agreement, Contract No. 99TX-10236 (BPA intends to offer this agreement prior to the execution of the Construction Agreement)

6.14 ENTIRE AGREEMENT

This Service Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

ARTICLE 7
SIGNATURES

The signatories represent that they are authorized to enter into this Service Agreement on behalf of the Party for whom they sign.

HERMISTON POWER PARTNERSHIP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ RANDOLPH J. HILL	By: /S/ SUSAN E. GARIFO FURST
Name: Randolph J. Hill (Print/Type)	Name: Susan E. Garifo Furst (Print/Type)
Title: Member Management Commmittee	Title: Transmission Account Executive
Date: May 10, 1999	Date: 9 April 1999

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

1. TERM OF TRANSACTION

Start Date: at 2400 hours on June 30, 2001.

Termination Date: The earlier of : (a) 2400 hours on June 30, 2021; or (b) 2400 hours on the termination date established pursuant to Article 3 of this Service Agreement.

2a. SUMMARY OF NETWORK POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party	Scheduling Agent[2/]
Hermiston Power Project	McNary 500 kV [3/]	BPA	See Sect. 3 below	John Day 500 kV	BPA	See Sect. 3 below	BPA	BPA
				Big Eddy 500 kV	BPA	See Sect. 3 below	BPA	BPA
Total Transmission Demand			See Sect. 3 below			See Sect. 3 below		

[1/] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.
[3/] This POI may change to the substation adjacent to the Hermiston Power Project (HPP) if a transmission line connecting HPP to the McNary Substation is built to BPA standards.

2b. SUMMARY OF INTERTIE POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party	Scheduling Agent[2/]
Hermiston Power Partnership	John Day Substation 500 kV	BPA	See Sect 3 below	COB, 500 kV	BPA	See Sect. 3 Below		BPA
	Big Eddy 500 kV	BPA	See Sect 3 below	NOB 1000 kV	BPA	See Sect. 3 below		BPA
Total Transmission Demand			[3/]			[3/] [4/]		

3a. SUMMARY OF INTERTIE POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

(a) July 1, 2001 - June 30 2003

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
John Day Substation 500 kV	308,000	COB 500 kV	308,000
Big Eddy 500 kV	228,000	NOB 1000 kV	228,000
Total Transmission Demand	**536,000**		**536,000**

[1/] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

(a) **July 1, 2003 – June 30, 2021**

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
John Day Substation 500 kV	536,000	COB 500 kV	536,000
Total Transmission Demand	**536,000**		**536,000**

3b. SUMMARY OF NETWORK POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

(a) **July 1, 2001 – June 30, 2003**

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
McNary Substation 500 kV	536,000	John Day Substation 500 kV	308,000
		Big Eddy 500 kV	228,000
Total Transmission Demand	**536,000**		**536,000**

(a) **July 1, 2003 – June 30, 2021**

Point of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point of Delivery (Voltage)	Maximum Transmission Demand (kW)
McNary Substation 500 kV	536,000	John Day Substation 500 kV	536,000
Total Transmission Demand	**536,000**		**536,000**

Reservation Fee: The first year of the extension period for commencement of service shall begin on the effective date of the Service Agreement. The first annual nonrefundable reservation fee of $1,218,864 shall be payable within 30 days of the effective date of this Service Agreement. For each subsequent full or partial year of the extension period for commencement of service, the annual nonrefundable reservation fee of $1,218,864 shall be billed within 30 days of the beginning of the subsequent year.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) MCNARY POINT OF INTERCONNECTION

Location: (to be determined from Projects Requirements Diagram (PRD) in the Construction Agreement).

Voltage: 500 kV

Metering: (to be determined from PRD).

(b) JOHN DAY SUBSTATION POINT OF INTERCONNECTION

Location: The point in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: Scheduled quantities

(c) BIG EDDY SUBSTATION POINT OF INTERCONNECTION

Location: The point in the Government's Big Eddy Substation where the Government's Celilo converter station are connected to the 500 kV bus.

Voltage: 1000 kV

Metering: Scheduled quantities

5. POINTS OF DELIVERY

(a) CALIFORNIA – OREGON BORDER (COB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the California Oregon border (COB) where Bonneville shall make Electric Power available for the Transmission Customer hereunder.

Voltage: 500 kV

Metering: Scheduled quantities

(b) NEVADA – OREGON BORDER (NOB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada Oregon border (NOB) where Bonneville shall make Electric Power available for the Transmission Customer hereunder.

Voltage: 1000 kV

Metering: Scheduled quantities

Receiving Control Area: Los Angeles Department of Water and Power

(c) JOHN DAY SUBSTATION:

Location: The point in the Government's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus.

Voltage: 500 kV

Metering: Scheduled quantities

(d) BIG EDDY SUBSTATION

Location: The point in the Government's Big Eddy Substation where the Government's Celilo converter station are connected to the 500 kV bus.

Voltage: 500 kV

Metering: Scheduled quantities

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Hermiston Power Partnership

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE None

8. SHORT-DISTANCE DISCOUNT (SDD)
None

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FACILITIES CHARGES

Specifics of the Transmission Customer's obligation to BPA for the Transmission Customer's future use of BPA's McNary-Roundup right of way, shall be determined in the negotiations of the Construction Agreement, Contract No. 99TX-10238. This Facilities Charges Exhibit will be updated at that time.

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ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL[1/])	98TX-10154
(b)	**Energy Imbalance**	BPA (TBL[1/])	98TX-10154
(c)	**Control Area Reserves for Resources**	BPA (TBL[1/])	98TX-10154
(d)	**Control Area Reserves for Interruptible Purchases**	N/A	
(e)	**Load Regulation**	N/A	
(f)	**Reactive Supply and Voltage Control**	BPA (TBL)	
(g)	**Transmission Losses**	BPA (TBL[1/])	98TX-10154

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) **Transmission Losses Associated with Federal Power**
Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) **Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power**
The Transmission Customer shall compensate BPA for losses BPA incurs when providing Transmission Service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be

[1/] BPA's Transmission Business Line.

determined by multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in section 2; and

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) **Transmission Losses Associated with Delivery Facilities**
Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year [2/] pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) **Notification**

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice for compensating BPA for

[2/] Fiscal Year is defined as the twelve-month period from October 1 through September 30.

transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit C.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate in the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) **Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year**

The Transmission Customer has elected to return Transmission Losses for the period 2400 hours June 30, 2001, through 2400 hours September 30, 2002. The Transmission Customer will return the losses from a single Control Area in the Pacific Northwest, as defined in the Pacific Northwest Electric Power Planning and Conservation Act. The name of that Control Area is BPA.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit C as appropriate, but not more frequently than once in a 12-month period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit C incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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AUTHENTICATED REVISION NO. 11, EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR
LONG-TERM FIRM TRANSMISSION SERVICE

This Revision No. 11 reflects an assignment [1] of transmission service under this Service Agreement from Assignor Hermiston Power Partnership (HPP) to Assignee PPM Energy, Inc. (PPM) [2]and is contingent upon execution of such assignment. This revision decreases HPP's intertie transmission demand by 50 MW at the John Day Substation Point of Interconnection (POI) and at the California-Oregon Border Point of Delivery (POD) for the period January 1, 2005, through December 31, 2005.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2005.
Termination Date: at 2400 hours on June 30, 2021.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

(a) Network POIs and PODs: Hermiston Power Project

Delivering Party (Resource) [3]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party and Scheduling Agent
Hermiston Power Project	McNary (500 kV)	BPA	See §3 below	John Day (500 kV)	BPA	See §3 below	Calpine Energy Services, L.P.
				Big Eddy (500 kV)			

Total Reserved Capacity: See section 3 below.

(b) Intertie POIs and PODs: Hermiston Power Project

Delivering Party (Resource) [3]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party and Scheduling Agent
Hermiston Power Project	John Day Substation (500 kV)	BPA	See §3 below	COB (500 kV)	BPA	See §3 below	Calpine Energy Services, L.P.
	Big Eddy	BPA	See §3 below	NOB	BPA	See §3 below	Calpine

[1] See section 3(b)(1).
[2] See Exhibit A, Table 11, PPM Service Agreement, Contract No. 00TX-10367.
[3] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at time of preschedule.

	(500 kV)			(1000 kV)			Energy Services, L.P.

Total Reserved Capacity: See section 3 below.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

(a) Network POIs and PODs

(1) January 1, 2005 - June 30, 2021

The OASIS Assignment Reference Numbers (ARef) are: 626252 and 420845.

Point(s) of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point(s) of Delivery (Voltage)	Maximum Transmission Demand
McNary Substation (500 kV)	Jan 05 - Feb 05 536,000 Mar 05 - Jun 21 308,000	John Day Substation (500 kV)	Jan 04 - Feb 05: 536,000 kW Mar 05 - Jun 21: 308,000 kW
	Mar 05 - Jun 21 228,000	Big Eddy Substation (500 kV)	Mar 05 - Jun 21: 228,000 kW
Total Maximum Transmission Demand	**536,000**		**536,000 kW**

(b) Intertie POIs and PODs

(1) January 1, 2005 - June 30, 2021

The OASIS Assignment Reference Numbers (ARef) are: 449487, 449490, 449491, 449493, and 596897.

Point(s) of Interconnection (Voltage)	Maximum Transmission Demand (kW)	Point(s) of Delivery (Voltage)	Maximum Transmission Demand
John Day Substation (500 kV)	Jan 05 - Feb 05: 486,000[1] Mar 05 - Dec 05: 258,000[1] Jan 06 - Jun 21: 308,000[1]	COB (500 kV)	Jan 05 - Feb 05: 486,000 kW[1] Mar 05 - Dec 05: 258,000 kW[1] Jan 05 - Jun 21: 308,000 kW[1]
Big Eddy (500 kV)	Mar 05 - Jun 21: 228,000	NOB (1000 kV)	Mar 05 - Jun 21: 228,000 kW
Total Maximum Transmission Demand	**536,000[2]**		**536,000 kW[2]**

[1] Reflects an assignment to PPM of 50 MW (see PPM Contract No. 00TX-10367, Exhibit A, Table 11) under Revision No. 11, and excludes any assignment participation under BPA's Pilot Program for Partial Assignment of Transmission Service.

[2] The Maximum Transmission Demand for the period 1/1/05 through 12/31/05 is 486,000 kW.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) Big Eddy Substation Point of Interconnection

Location: the point in the Transmission Provider's Big Eddy Substation where the Transmission Provider's Celilo converter station is connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) John Day Substation Point of Interconnection

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(c) McNary Point of Interconnection

Location: the point in the vicinity of the Transmission Provider's McNary Substation at Bay 7, where the 500 kV facilities of the Transmission Provider and the Transmission Customer are connected;

Voltage: 500 kV;

Metering: Calpine's HPP Substation.

5. POINTS OF DELIVERY

(a) Big Eddy Substation

Location: the point in the Transmission Provider's Big Eddy Substation where the Transmission Provider's converter station is connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB), where Bonneville shall make Electric Power available for the Transmission Customer hereunder;

Voltage: 500 kV;

Metering: scheduled quantities.

(c) **John Day Substation**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

(d) **Nevada - Oregon Border (NOB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB) where Bonneville shall make Electric Power available for the Transmission Customer hereunder;

Voltage: 1000 kV;

Metering: scheduled quantities;

Receiving Control Area: Los Angeles Department of Water and Power.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Hermiston Power Partnership.

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

8. **SHORT-DISTANCE DISCOUNT (SDD)**
None.

HERMISTON POWER PARTNERSHIP	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ MIKE ROGERS**	By: **/S/ NANCY E MORGAN**
Name: **Mike Rogers** *(Print/Type)*	Name: **Nancy E. Morgan** *(Print/Type)*
Title: **Vice President**	Title: **Transmission Sales Manager**
Date: **1/05/05**	Date: **1/7/05**

(W:\TMC\CT\H P P\Revisions\10154R11A.doc) 11/10/04

Contract No. DE-MS79-94BP94285
05/25/94

AC INTERTIE TRANSMISSION AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP

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This AC INTERTIE TRANSMISSION AGREEMENT, executed June 1, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS Bonneville and PacifiCorp, on August 27, 1982, entered into Contract No. DE-MS79-81BP90424, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract"; and

WHEREAS PacifiCorp and the Western Area Power Administration Sacramento Area Office (Western) have entered into a contract dated September 17, 1992, which, as amended or replaced, is hereinafter referred to as "Western Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to Western; and

WHEREAS PacifiCorp and the City of Redding (Redding) have entered into a contract dated October 19, 1993, which, as amended or replaced, is hereinafter referred to as "Redding Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to the City of Redding; and

WHEREAS Bonneville and PacifiCorp entered into an Intertie Agreement, Contract No. DE-MS79-86BP92299, as amended, effective July 8, 1986, which is hereinafter referred to as " Intertie Agreement", and the Parties have replaced such agreement with Contract No. DE-MS79-94BP94332, which, as amended or replaced, is hereinafter referred to as "AC Intertie Agreement"; and

WHEREAS Bonneville and PacifiCorp have entered into a Letter of Understanding (LOU) dated May 28, 1993, which provides that Bonneville shall under certain circumstances offer PacifiCorp interim and long-term firm transmission contracts providing wheeling for PacifiCorp's Western Sales Agreement and Redding Sales Agreement, and for nonfirm wheeling; and

WHEREAS Bonneville has developed the LTIAP, as defined below, which includes provisions for non-Federal access to the AC Intertie for transactions with Pacific Northwest and California utilities; and

WHEREAS the Parties agree that the terms and conditions of the LOU represent a Joint Venture pursuant to Section 4(b)(1) of the LTIAP; and

WHEREAS consistent with the LOU and in order to facilitate the arrangements provided for in the Western Sales Agreement and the Redding Sales Agreement, Bonneville will provide transmission service in a North-to-South direction from the Points of Interconnection, over the AC Intertie, for deliveries of Electric Power to Western, Redding, and other third parties at the Points of Delivery, and transmission service in a South-to-North direction from the Points of Interconnection, over the AC Intertie, to the Points of Delivery for the delivery of Electric Power to PacifiCorp; and

WHEREAS in accordance with the LOU, Bonneville will provide such access to the AC Intertie for firm and nonfirm transactions up to the Transmission Demand both in a North-to-South and South-to-North direction without regard to the source or ultimate user of services provided under such transactions; and

WHEREAS PacifiCorp and Bonneville desire to provide for such services pursuant to the terms of this Agreement and pursuant to the terms of the LTIAP; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. TERM OF AGREEMENT

This Agreement shall be effective on the Effective Date, and shall continue in effect until the earlier of (1) 2400 hours on December 31, 2018, or (2) the later of the termination date of the Western Sales Agreement or the Redding Sales Agreement. All liabilities incurred under this Agreement are hereby preserved until satisfied. Upon termination of this Agreement, Bonneville will offer to extend such services in an agreement to be executed by the Parties for a period of up to 25 years, based upon Bonneville's then standard terms included in similar agreements, provided that no mitigation charges shall be applied, beyond the applicable FERC-approved Bonneville rates, if PacifiCorp requires such service.

2. DEFINITION AND EXPLANATION OF TERMS

(a) "AC Intertie" means Bonneville's rights in the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line, Bonneville's rights in the Meridian-Malin 500 kV transmission line, Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 10 kilometer 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, improvements, or additions to such facilities.

(b) "Agreement" means this AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285.

(c) "Billing Energy" means the net amount of Electric Energy scheduled in a North-to-South direction and in a South-to-North direction during a month hereunder.

(d) "COB" means the California-Oregon border.

(e) "DC Intertie" means Bonneville's rights in the 1000 kV direct current (DC) transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to the Nevada-Oregon border.

(f) "Demand Charge" means the demand charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(g) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system

related to the disturbances of concern, thereby providing acceptable power system performance.

(h) "Effective Date" means 2400 hours on the date of execution.

(i) "Electric Energy" means electric energy, expressed in kilowatthours.

(j) "Electric Power" or "power" means electric peaking capacity, expressed in kilowatts, Electric Energy, or both.

(k) "Energy Charge" means the energy charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(l) "FCRTS" means the Federal Columbia River Transmission System and other Pacific Northwest facilities over which Bonneville has transmission rights.

(m) "FERC" means the Federal Energy Regulatory Commission, or its successor agency.

(n) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, and amended on April 8, 1993, attached hereto as Exhibit E.

(o) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency, loading condition, or maintenance outage on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce AC Intertie loadings, whether or not all facilities are in service.

(p) "OTC" or "Operational Transfer Capability" means the RTC less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, and Operational Constraints, as determined by Bonneville, resulting from, among other things, line or equipment outages, stability limits, or loopflows.

(q) "Pacific Northwest" is as defined in the LTIAP.

(r) "Points of Delivery" means the points, specified and described in Exhibit C, where Electric Power made available by or on behalf of PacifiCorp shall be delivered by Bonneville.

(s) "Points of Interconnection" means the points, specified and described in Exhibit C, where Electric Power shall be made available by or on behalf of PacifiCorp to Bonneville for transmission over the AC Intertie.

(t) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts existing prior thereto in the electrical utility industry, in the Western Systems Coordinating Council area, or, if there are no such practices, methods, and acts, the practices, methods, and acts, which, in the exercise of reasonable judgment in the light of the facts which were known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(u) "RTC" or "Rated Transfer Capability" means the capability of a transmission line or system to transfer a specified quantity of Electric Power in a prudent and reliable manner.

(v) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville power flows and/or stability studies.

(w) "Transmission Demand" means the maximum amount of Electric Power that Bonneville shall be obligated to transmit during an hour hereunder. Such amount is specified in Exhibit C and shall be changed only upon mutual agreement of the parties.

(x) "Workday" means each day that PacifiCorp and Bonneville jointly observe as a regular workday.

3. EXHIBITS AND INTERPRETATIONS

The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement. This Agreement sets forth the entire agreement of the Parties as of the date of execution. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement. PacifiCorp shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. TRANSMISSION OF ELECTRIC POWER

(a) Subject to the other provisions of this Agreement, Electric Power shall be transmitted by Bonneville on a firm basis from South-to-North and from North-to-South over the AC Intertie, and PacifiCorp shall schedule pursuant to section 7(a) and make available, or arrange to have made available, to Bonneville at the Points of Interconnection the amounts of Electric Power that PacifiCorp determines are available for transmission to the Points of Delivery hereunder for each hour.

(b) The hourly amounts of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand as specified in Exhibit C.

(c) During times when the North-to-South OTC of the AC Intertie is less than the North-to-South RTC, PacifiCorp's reduced net North-to-South scheduling rights shall be an amount determined by multiplying the North-to-South OTC of the AC Intertie by the ratio of PacifiCorp's North-to-South Transmission Demand to the North-to-South RTC of the AC Intertie. During times when the South-to-North OTC of the AC Intertie is less than the South-to-North RTC, PacifiCorp's reduced net South-to-North scheduling rights shall be an amount determined by multiplying the South-to-North

OTC of the AC Intertie by the ratio of PacifiCorp's South-to-North Transmission Demand to the South-to-North RTC of the AC Intertie.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints. The amount of curtailment shall be consistent with Prudent Utility Practice.

(e) PacifiCorp shall be responsible for providing or assuring at its cost the provision of its pro rata share of Remedial Action Schemes required to support the RTC and OTC of the AC Intertie in either the South-to-North or North-to-South direction. Bonneville and PacifiCorp shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. PacifiCorp may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective Control Action is obtained. The level of reliability of the Remedial Action Scheme design on PacifiCorp's system shall be at least equal to the level of reliability employed in the design of the overall AC Intertie Remedial Action Scheme.

(1) PacifiCorp's contribution to the total operational responsibility for this Remedial Action Scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the total RTC of the AC Intertie.

(2) Bonneville shall provide the appropriate control signal or signals to PacifiCorp.

(3) PacifiCorp shall provide the necessary equipment to receive and transmit the control signal or signals to and from PacifiCorp's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions as determined by Bonneville.

(4) In support of its obligations to provide generator dropping for its net North-to-South AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on-line at the time of the Remedial Action Scheme requirement.

(5) Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net North-to-South AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on-line at the time of the Remedial Action Scheme requirement. Such access to PacifiCorp's Mid-Columbia generator dropping capability by Bonneville shall be at no cost to Bonneville.

(6) To the extent that PacifiCorp does not have the capability on-line to provide generator dropping from its Mid-Columbia rights for its net North-to-South AC Intertie schedules, Bonneville shall, to the extent it has available on-line generation, provide generator dropping capability to PacifiCorp at no cost to PacifiCorp.

(7) In support of PacifiCorp's net South-to-North schedules on the AC Intertie, PacifiCorp shall be responsible for making arrangements for any load dropping requirements.

(8) To the extent possible, as determined by Bonneville, Bonneville shall offer to sell Remedial Action Scheme service to PacifiCorp to enable PacifiCorp to meet its obligations under this section 4(e).

(9) Nothing in this section 4(e) shall be construed so as to diminish in any way PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the RTC and the OTC of the AC Intertie in either the North-to-South or South-to-North direction.

(f) When PacifiCorp schedules deliveries pursuant to this Agreement or any agreement for use of AC Intertie capacity entered into pursuant to the LOU, including future Pacific Northwest AC Intertie Capacity Ownership

Agreements, PacifiCorp shall not be required to obtain additional main grid wheeling on Bonneville's system unless insufficient capacity exists in the combined capability of the Midpoint-Malin 500 kV line, the Malin-Meridian Line, and the Alvey-Meridian line for PacifiCorp to use its scheduling rights available to it. If there is insufficient capacity in the combined capability of the Midpoint-Malin line, the Malin-Meridian Line, or the Alvey-Meridian Line, charges will be applied by Bonneville to PacifiCorp consistent with subsection 5(e)(3) of the AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

5. PAYMENT PROVISIONS

(a) As compensation for the AC Intertie transmission services provided hereunder, PacifiCorp shall pay Bonneville, in accordance with the provisions of Exhibits B and C, and as follows:

(1) PacifiCorp shall pay Transmission Demand charges for North-to-South and for South-to-North service, which shall equal the sum of the products obtained by multiplying the North-to-South and the South-to-North Transmission Demands for each month by the Demand Charge; and

(2) PacifiCorp shall pay for energy transmitted hereunder each month, determined as follows:

(A) For North-to-South service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall be the greater of (1) the product obtained by multiplying the North-to-South Billing Energy for each month by the Energy Charge, or (2) a minimum energy payment, based upon the Energy Charge and an 85 percent load factor. Such minimum energy payment shall be calculated as follows: Transmission Demand (MW) x 8760 hours x Energy Charge (m/kWh) x 0.85 ÷ 12; and

(B) For South-to-North service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall equal the product obtained by multiplying the South-to-North Billing Energy for each month by the Energy Charge.

(C) Such payment shall include charges determined by multiplying the amount of hourly losses, calculated in accordance with the transmission loss factor specified in Exhibit D, by the Energy Charge.

6. TRANSMISSION LOSSES

To compensate Bonneville for Electric Power losses incurred in providing the services hereunder, both for deliveries from PacifiCorp and for deliveries to PacifiCorp, PacifiCorp shall schedule and make available to Bonneville on the corresponding hour 168 hours later or on another hour to be agreed upon by the Parties, and at points to be agreed upon by the Parties, the amounts of Electric Power calculated in accordance with the Loss Factors specified in Exhibit D.

7. POWER SCHEDULING

PacifiCorp shall submit, or arrange to have submitted, to Bonneville by 1400 hours Pacific Time on each Workday:

(a) a separate schedule for North-to-South and South-to-North transfers of Electric Power to be made available to Bonneville for each hour of the following day or days through the next Workday. Such North-to-South and South-to-North schedules may be netted against each other. Changes to such schedules by PacifiCorp shall be accepted up to 30 minutes prior to the hour for which such schedule change is desired;

(b) separate schedules of the hourly amounts of Electric Power to be made available pursuant to section 6 for transmission losses for each hour of the following day or days through the next Workday;

(c) changes to schedules other than those permitted pursuant to subsection 7(a) shall be accepted at any time as mutually agreed by the Parties.

8. REVISION OF EXHIBITS

(a) The initial rate schedules attached as Exhibit B have been confirmed and approved by the FERC on an interim basis. The UFT rate schedule has been approved on a final basis. If the final rate schedules which are approved by the FERC are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated General Transmission Rate Schedule Provisions shall be attached hereto and made a part of this Agreement effective as of the date specified in the FERC's approval.

(b) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) and FERC rules.

(c) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then current AC Intertie and DC Intertie operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, which has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with PacifiCorp. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that any charge specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate incorporating such revised charges. Such new exhibit

shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(e) If the Parties agree to any changes to Exhibit C pursuant to this Agreement Bonneville shall prepare and issue a revised Exhibit C.

9. WAIVER OF BONNEVILLE'S ENERGY SERVICE OBLIGATION

(a) PacifiCorp agrees that the disposition of Electric Energy for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement shall result in a reduction of Bonneville's obligation to PacifiCorp under section 5(b) of the Northwest Power Act. Bonneville's obligation to supply firm power under the Power Sales Contract, as amended or replaced, shall be reduced by the maximum amount of Electric Energy which PacifiCorp is obligated to provide for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement. Bonneville shall implement such reduction as described in subsection (b) below.

(b) To carry out the provisions of subsection (a) above, PacifiCorp shall submit to Bonneville a revised Firm Resources Exhibit and associated data as specified under the Power Sales Contract effective on the effective date of the notice pursuant to subsection (a) above. The Firm Resources Exhibit shall include, as a Firm Resource, the amount of PacifiCorp's obligation to provide Electric Energy for use outside of the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement.

10. COMPLIANCE WITH LONG-TERM INTERTIE ACCESS POLICY

Except as otherwise specified in this Agreement, transmission service provided by Bonneville to PacifiCorp over the AC Intertie shall be subject to the terms of the LTIAP. Notwithstanding the terms of the LTIAP, the Parties agree that no mitigation charges shall be applicable under this Agreement. The Parties also agree that the transmission services being provided hereunder are in accordance with Section 4(b) of the LTIAP (New Transactions not subject to Capacity Limits). The

terms of this Agreement shall not be subject to change upon amendment of the LTIAP, except by mutual agreement of the parties; provided, however, Bonneville may change the Protected Areas Exhibit C to the LTIAP and apply such changes prospectively to resources not licensed at the time of the change without the agreement of PacifiCorp. A resource which has been licensed in the past, and for which a new license is pending, shall be considered licensed.

11. PACIFIC NORTHWEST AC INTERTIE CAPACITY OWNERSHIP EXCHANGE RIGHTS

PacifiCorp shall have the right to exchange all or a portion of its AC Intertie firm transmission contract rights acquired under this Agreement with any party receiving Pacific Northwest AC Intertie Capacity Ownership (Capacity Ownership) rights for up to 125 MW of Capacity Ownership rights, to the extent the Capacity Ownership party has rights to assign all or a portion of its Capacity Ownership allocation. To the extent Bonneville has a first right of refusal to acquire Capacity Ownership rights from a Capacity Ownership party, PacifiCorp's exchange rights under this section 11 shall have priority. Such exchange between PacifiCorp and the Capacity Ownership party shall be approved by Bonneville, which approval shall not unreasonably be withheld, and shall ensure that rights, benefits and obligations

to Bonneville under the affected agreements are preserved.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
ACTING *Assistant Administrator for Power Sales*

Name Sydney D. Berwager
(Print/Type)

Date 5/26/94

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date June 1, 1994

(PMTT-8170-W:PMT\CT\PACAD.DOC)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. *Reducing Charges for Interruptions*. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{/(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Exhibit B

1993

TRANSMISSION RATE SCHEDULES AND

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

Transmission Parameters

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1]

1. North-to-South Transactions:

   a. 01/01/94 to 05/31/94: 75 MW

   b. 06/01/94 and thereafter: 125 MW

2. South-to-North Transactions:

   a. 01/01/94 to 05/31/94: 75 MW x Intertie South-to-North RTC ÷ 4800 MW

   b. 06/01/94 and thereafter: 125 MW x Intertie South-to-North RTC ÷ 4800 MW

[1] Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

Transmission Loss Factors

Transmission Loss Factor to be Applied to Transmission Pursuant to the Southern Intertie Transmission (IS) Rate Schedule

Rate Schedule	Loss Factor
IS-93 B	3.0%

EXECUTIVE SUMMARY

LONG-TERM INTERTIE ACCESS POLICY

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

INTRODUCTION

The Pacific Northwest-Pacific Southwest Intertie began operation in 1968. Congress authorized the construction of the Intertie to provide an additional market for surplus BPA power, thereby providing greater assurance that we would repay the U.S. Treasury for the Federal investments in the Northwest's power system. To the extent there was capacity excess to Federal needs, Congress also intended that the Intertie allow nonfederal utilities in the Northwest and California to take advantage of the diverse load patterns and resource types between the two regions.

The present capability of the Intertie is about 5,200 megawatts (MW), 3,200 MW on the two alternating-current (AC) lines and 2,000 MW on the direct-current (DC) line. Ownership of the Intertie in the Northwest is shared by BPA, Portland General Electric Company (PGE) and Pacific Power & Light Company (PP&L). We provide access to all Northwest generating utilities. Ownership in California is shared by four investor-owned and municipal utilities.

In the early 1980s demand for sales over the Intertie increased dramatically. Nearly every utility in the Northwest had excess power to sell and forecasted a surplus into the next decade and beyond. Northwest utilities frequently filled the Intertie with nonfirm energy and sought to negotiate long-term transactions with California. Prior to 1984 and the implementation of the Interim Intertie Access Policy (IAP), BPA lost significant revenue opportunities by allowing other utilities unfettered access to the Intertie. Combined effects of (1) the Northwest Preference Act, 16 U.S.C. §837, et seq., which gives Northwest utilities a special competitive advantage over us; (2) oversupply conditions in the Northwest; and (3) a restricted market in California due to limited ownership of the Intertie in California caused us to lose sales. We were unable to make our payments to the U.S. Treasury.

In 1984 we implemented the Interim IAP, followed by the Near-Term IAP in 1985. These policies governed access to the Intertie while we developed a Long-Term Intertie Access Policy (LTIAP).

The LTIAP, issued by the Administrator on May 17, 1988, accomplishes the following objectives which have guided us throughout the process:

1. The LTIAP assures BPA of reasonable access to the Intertie to sell both firm and nonfirm energy, thereby enhancing our ability to repay, with interest, $8 billion in Treasury investments.
2. The policy is a reasonable and effective means of safeguarding our $120 million investment in fish and wildlife protection.
3. It balances the competing demands of nonfederal utilities for Intertie access to sell, exchange, or purchase both firm power (through long-term contracts) and nonfirm energy (through the short-term, spot-market).

4. It provides a basis for greater planning certainty to utilities.
5. It allows for efficient use of generating resources in the Northwest and California.
6. It specifically addresses competitive concerns between California and the Northwest.
7. In doing all of the above, it strikes a balance between the Northwest and California, among generating and nongenerating utilities, other BPA customers, environmental interests and Federal taxpayers.

Issuance of this policy culminates our review of comments submitted by over 150 different utilities, regulatory agencies and interest groups. Through a combination of formal, transcribed meetings and informal discussions, we have increased our knowledge of their positions -- and they of ours. We have twice appeared before the U.S. House Subcommittee on Water and Power Resources to answer questions regarding the IAP. Though often cumbersome and lengthy, the process has produced a policy which addresses the demands of all parties.

Balancing interests. We have been put in the difficult position of balancing the competing interests for use of the Intertie. The sum of the demands placed on the Intertie far exceeds the facility's ability to meet them.

Our total-requirements customers insist that BPA should protect its revenues in order to maintain stable power rates and to repay the U.S. Treasury in a timely manner. They suggest that BPA should allocate firm and nonfirm Intertie access to itself first, always assuring that BPA would be able to sell its surplus power. Northwest generating utilities seek a policy which allows sufficient and assured access for their own firm and nonfirm sales. California parties generally argue for a policy which allows them unconstrained access to inexpensive Northwest and Canadian resources. Environmental organizations support a policy that would prevent the Intertie from encouraging development that would harm fish and wildlife resources.

Our main concern in reaching this balanced policy has been reconciling BPA's need to meet its fiscal obligations with these other competing demands for use of the Intertie. While BPA has the discretion to implement the "Federal-first" policy supported by our full requirements customers, the LTIAP instead provides significant access to nonfederal utilities for a variety of transactions while protecting BPA from revenue shortfalls.

It is not reasonable to suggest, as California commenters did in the public process, that BPA incur revenue losses to be recovered through rate increases to its total-requirements customers. These customers have a strong statutory argument -- explained in the decision -- that we should adopt a Federal-first policy to maximize Federal sales over the Intertie. By rejecting Federal-first, we incur an obligation to provide these customers with rate stability through alternative means. First among these alternative protections is the reservation of Intertie capacity for BPA sales.

If the revenue-protective measures adopted in the LTIAP prove unworkable or unduly controversial, the obvious remedy is not more access for nonfederal utilities. Instead, it is Federal-first.

FORMULA ALLOCATION

The Intertie accomodates transactions in two distinct markets. Sellers of power to California sell in two distinct markets, one for long-term transactions and one for short-term sales. Formula Allocation in the LTIAP refers to Intertie capacity made available for short-term sales of energy. We have taken a hard look at Formula Allocations as it has been one of the most hotly debated issues throughout the LTIAP's development.

The LTIAP continues the basic Formula Allocation method used in the Near Term Intertie Access Policy (NTIAP) of allocating access to the Intertie based on three possible conditions. We have changed the specifics of each Condition to reflect criticisms and suggestions made on the two LTIAP drafts. Provisions for Conditions 2 and 3 address directly the contentious anti-competitive concerns between California and the Northwest.

Condition 1. Condition 1 under the NTIAP incorporated the pre-existing Exportable Agreement, which expires on December 31, 1988. Parties to the agreement declare amounts of surplus energy available for export at the applicable BPA rate. If total declarations of exportable energy exceed the available Intertie Capacity or the size of the Pacific Southwest market, whichever is smaller, each party to the agreement is allocated access to the smaller amount based on its share of total declarations.

The 1986 draft LTIAP proposed that upon expiration of the Exportable Agreement a condition of spill or likelihood of spill on the Federal Columbia River Power System (FCRPS) would trigger Condition 1. BPA and Northwest Scheduling Utilities could declare surplus energy available for export and BPA would allocate access to the Intertie based on the ratio of each declaration to the sum of all declarations multiplied by the available Intertie Capacity. Each Scheduling Utility's allocation would be limited by the ratio of its regional hydroelectric capacity to the total regional hydroelectric capacity of the Scheduling Utilities multiplied by the total of all declarations (the "Hydro Cap").

We received comments on the 1986 draft which led us to revise Condition 1 to mirror the Exportable Agreement more closely. Under the 1987 draft a condition of spill or likelihood of spill on the FCRPS determined Condition 1. BPA and Scheduling Utilities could declare surplus energy available for export at the applicable BPA rate and receive a share of available Intertie Capacity based on the Hydro Cap. To the extent that the market for Northwest energy at BPA's price was less than the available Intertie Capacity, we allocated access to the Intertie to equal that market.

Generally, commenters on the 1987 draft did not argue against Condition 1 per se. They focused instead on its specific provisions. The bulk of the comments were directed at the Hydro Cap and at allocating Intertie capacity based on the size of the California market rather than the size of the Intertie capacity. In response to concerns heard at the public meetings in January 1988, we proposed an alternative Condition 1 allocation method. The LTIAP adopts this recent proposal.

The True-Up. The market for power in California is often less than the available Intertie capacity because of minimum generation requirements in California. As the Intertie is expanded and Southwest utilities bring on new generation that cannot be displaced with spot-market purchases, the frequency of this situation is likely to grow.

The 1987 draft allocated Intertie capacity based on the size of the California market as a protection against revenue shortfalls. Analyses indicated that we would lose approximately $16.4 million in 1989 by allocating to the Intertie rather than the market. This loss would decrease to $10.7 million in fiscal year 1992. Beyond 1992 the difference would increase, mainly due to projected fuel price increases.

The heart of the revenue problem is the Northwest Regional Preference Act, 16 U.S.C. 837, et seq., which requires BPA to quote an energy price to Northwest utilities before making any sale to the Southwest. This creates a problem in which Northwest utilities, which are BPA's competitors, know our price -- but we do not know their prices. In Condition 1, where the size of the Southwest market is less than available Intertie Capacity, Northwest utilities are able to use this information to undercut the BPA price and use their allocations to reduce BPA's hourly sales to a small Southwest market. If a "real-time" BPA pricing iteration were even possible, we would still be required to announce our new price to the Northwest. Regional preference makes BPA a "sitting duck" for its competitors.

Allocating according to the California market size would reduce BPA's vulnerability by reducing the size of Scheduling Utility allocations. This provision came under attack, however, from both California and Northwest parties. The alternative discussed at the January 27 public meeting seemed to allay concerns regarding BPA's market control. No one disputes that the Regional Preference Act causes BPA a revenue dilemma, especially at times when we face spill on the hydro system. The true-up alternative is the least intrusive remedy.

The Hydro Cap. Both the 1986 and 1987 LTIAP drafts allocated Intertie capacity based on a utility's hydroelectric capability. The logic for the Hydro Cap was that when the Federal system is spilling or likely to spill, the maximum allocation to utilities with greater hydroelectric resources would increase, thus decreasing the probability of wasting the resources by spilling. Under this provision, BPA's share of allocations would tend to increase due to its large hydroelectric capacity.

Much of the debate over the Hydro Cap focused on two issues. First, removing the Hydro Cap could cause hydro-based utilities to spill. Second, without the Hydro Cap, utilities could "overdeclare" by including uneconomic combustion turbines in their declarations with no intent of ever operating them.

Discussion at the January meetings helped resolve these concerns. When the Federal hydro system faces spill, other systems might not always be in the

same condition. The Hydro Cap could give disproportionately large shares of Intertie Capacity to hydro-based utilities when they may not face a threat of spill, while frustrating the marketing activities of utilities with hydro and thermal resources. Furthermore, several utilities and BPA indicated that if a utility is facing spill with insufficient access to market the available energy on the Intertie, such energy could generally displace Northwest thermal generation.

Several factors would help deter overdeclarations. First, the take-or-pay feature of our IS-87 transmission rate requires a utility to pay for its allocation whether or not it is used. Second, BPA monitors declarations and is aware of each utility's resources and capabilities. We have not observed significant overdeclarations under past policies. Third, from time to time we can request documentation on each utility's declaration as a further insurance against abuse.

Conditions 2 and 3. Allegations of anti-competitive practices on both the northern and southern portions of the Intertie were made during the debate over Formula Allocations. California commenters argue that pro-rata allocations to nonfederal utilities under the LTIAP would tend to stabilize prices at levels higher than those at which sellers might increase their total sales by reducing prices. The Northwest just as logically concludes that pro-rata allocations of California Intertie capacity suppress prices below levels that would prevail in a market where more buyers independently bid for Northwest energy.

We recognized that in implementing a long-term policy we must try to resolve this issue to meet the goals outlined for the LTIAP. We therefore proposed in section 5(d) of the 1987 draft LTIAP to cease pro-rata allocations to non-Federal utilities under Conditions 2 and 3 after completion of the third AC Intertie, provided anti-competitive problems in the Southwest were cured by that time. This proposal was discussed extensively during the public meetings in January 1988 and again in comment letters, mainly from California parties. The final LTIAP takes this proposal a step further. Section 5(d) now ceases pro-rata allocations under Conditions 2 and 3 for an 18-month experimental period.

We will analyze the success or failure of the experiment throughout its term. We will be particularly concerned about the removal of restrictions on California's portion of the Intertie. Utilities, regulators, and other interested parties will be encouraged to express their views in writing and through informal discussions. At least 30 days before the experiment ends, we will issue a written report on whether to continue the experiment.

The experiment will work as follows. Under Condition 2, when the declarations of BPA and Northwest utilities exceed Intertie capacity, we will make a pro-rata allocation to BPA and leave the remaining block of Intertie capacity available to Northwest utilities as a whole. Each Northwest utility could then compete to make sales to Southwest utilities, with no assurance of any individual allocation. Under Condition 3, when the declarations of BPA

and Northwest utilities are less than Intertie capacity, BPA will receive an allocation equal to its declaration and Northwest utilities will receive a block allocation equal to the sum of their declarations. After regional utilities, U.S. extraregional utilities and then Canada have access to remaining Intertie capacity. During Condition 3, we expect significant competition whenever the size of the California market is less than Intertie capacity.

Until the experiment is in effect, Conditions 2 and 3 are similar to those in the NTIAP and the two LTIAP drafts.

The LTIAP retains pro-rata allocations under Condition 1. Allocation under Condition 1 appears to be of less concern to California commenters than allocation during other conditions. Alternative Formula Allocation proposals recognized the importance of pro-rata allocations when the Northwest faces spill conditions. Retention of Condition 1 allocations will (1) help assure nonfederal utilities of Intertie access when hydrological conditions might otherwise force them to spill, and (2) provide an enforcement mechanism for the Protected Area provisions described below.

Some commenters have suggested that we allow access to Canadian utilities equal to that of Northwest utilities. The courts, however, have upheld our policy that capacity excess to our needs must be provided on a fair and nondiscriminatory basis first to Northwest utilities. If the Free Trade Agreement between Canada and the United States now being considered in Congress and the Canadian parliament is implemented, the distinction between U.S. extraregional utilities and Canadian utilities will no longer be made.

ASSURED DELIVERY

Utilities seek firm access to the Intertie for long-term transactions. The LTIAP refers to this kind of access as Assured Delivery. The earlier NTIAP did not provide for Assured Delivery service.

Amount. The final LTIAP reserves 800 MW for Assured Delivery transactions. This is an increase from the 420 MW reserved in the 1986 draft. BPA lost $213 million in fiscal year 1987; we do not want to exacerbate this problem with the final LTIAP. Given these uncertainties, we are cautious about committing major portions of the Intertie for long-term nonfederal use.

Yet, the 800 MW upper limit in itself is a fairly dramatic departure from the past. It will facilitate a greater number and variety of firm transactions than before. Our studies indicate an annual revenue loss of approximately $9 million in lost nonfirm revenue and displaced firm power sales to our public agency customers. The revenue effects on BPA have been quantified further in a study by the PNUCC. These adverse revenue effects, offset by mitigation measures discussed below, have been found acceptable by a fairly broad cross-section of commenters.

In the public meeting and comment letters, most parties seemed satisfied with the 800 MW if we were to consider increasing it upon completion of the third AC project. BPA will reassess the 800 MW limit upon commercial operation or termination of the project.

Exhibit B Allocations. As for the limits on types of transactions, BPA is convinced of the wisdom of imposing limitations on firm power sales. These limits are shown in Exhibit B of the LTIAP. From the standpoints of environmental quality and financial risks, it seems appropriate to limit Assured Delivery capacity to the amount of firm surplus presently available in the Northwest for export sales. In a change from the 1987 draft policy, the LTIAP provides that Scheduling Utilities may use their individual Exhibit B amounts for sales or exchanges.

The final LTIAP does not allocate the remaining 356 MW of Assured Delivery capacity among Scheduling Utilities. That amount will be available for exchange transactions of Scheduling Utilities on a first-come, first-served basis.

We have reached agreement (or agreement in principle) covering 341 MW of Assured Delivery service. Agreements include a 20-year 105 MW firm power sale from Montana Power Company to Los Angeles Department of Water and Power; a 41 MW firm power sale from Tacoma City Light to Western Area Power Administration (WAPA); a 45 MW firm power sale from Longview Fibre/Cowlitz County Public Utility District to WAPA; and a 20-year 150 MW seasonal exchange between The Washington Water Power Company and Pacific Gas and Electric Company. Each of these agreements accommodates our lost revenue concerns differently.

To allow for maximum use of the Intertie, a utility granted Assured Delivery may shape its firm power sale into the months of September through December by delivering up to 1.8 times its Exhibit B amount. During those fall months, spot market energy sales to the Southwest tend to be less than in the spring when the region's hydroelectric dams are more often near or in a spilling condition. If a utility shapes Assured Delivery energy into the fall, less firm energy may be shaped into remaining months of the operating year so that the total energy delivered does not exceed its annual Exhibit B energy maximum for firm sales.

BPA will also continue to work with Nonscheduling Utilities to provide the opportunity to sell the output of their generating resources over BPA's Intertie capacity.

Mitigation. Mitigation refers to conditions imposed on a utility for an Assured Delivery contract. Intertie Capacity not available to BPA because of Assured Delivery contracts executed between a Northwest utility and a Southwest utility can reduce BPA revenues and inhibit BPA's ability to make its Treasury payments. During the operating year BPA often has power available to fully load the Intertie. Assured Delivery granted under these circumstances would reduce BPA's revenues, thereby putting at risk our ability to meet our obligations to the Treasury.

This fiscal concern is in potential conflict with the policy objective underlying the 800 MW of Assured Delivery -- assisting Northwest utilities in disposing of their surpluses by means of long-term firm power sales to the Southwest. Strong objection was received from our Priority Firm Power customers to our absorbing the entire cost (lost revenues) of these transactions and the subsequent passing of the costs to them in increased rates. California and Northwest generating utilities generally tend to agree that some form of mitigation is due BPA. They question the level of compensation and what provisions for mitigation should be included in the LTIAP.

The 1986 draft of the LTIAP allowed Assured Delivery without regard to the adverse impacts on BPA's ability to sell firm power or nonfirm energy. Both the 1987 draft and the LTIAP impose mitigation upon utilities with Assured Delivery contracts. The mitigation provisions in the LTIAP provide only partial compensation for the revenue impacts resulting from transactions, but provide sufficient assurance that these transactions over the Intertie will not harm our revenue recovery.

It would be a false precision to claim that we could develop mitigation measures that offset dollar-for-dollar the losses projected in any 20-year study. Assumptions about annual rainfall, gas prices, aluminum prices, and load growth make this exercise judgmental. With this limitation in mind, the LTIAP incorporates the following mitigation provisions.

One mitigation measure requires that during any hour in which prescheduled energy sales are made under Condition 1 and Condition 2 Formula Allocation

procedures, a utility must deduct its Assured Delivery amount from its Formula Allocation amount. The total amount of Intertie access granted to each utility is equal to its Formula Allocation. If a utility's Assured Delivery amount is greater than its Formula Allocation, then that utility must purchase enough energy from BPA or, during Condition 1, other Northwest utilities to make up the difference. This mitigation measure will partially offset the spot-market revenues BPA will lose by granting Assured Delivery.

Under the other mitigation measure, if BPA has invoked Condition 1 or Condition 2 Formula Allocations, cash out provisions of exchange contracts become inoperative. Cash outs allow a Northwest utility to accept dollar payments from a Southwest utility in lieu of actual energy returns. Prohibiting these during Conditions 1 and 2 has the effect of increasing the north-to-south capability of the Intertie when energy is being returned and increasing the size of the market for BPA and Scheduling Utility sales.

The draft LTIAP required energy returns under seasonal exchanges to the California/Oregon border (COB) or the Nevada/Oregon border (NOB). This was initially included in the mitigation provisions for seasonal exchanges. However, BPA needs the certainty of available capacity resulting from return requirements at COB/NOB. For this reason, the final LTIAP includes this provision as a standard requirement for all exchanges rather than considering it a mitigation measure.

The LTIAP also allows utilities the opportunity to negotiate individual packages of mitigation in addition to the LTIAP's stated mitigation provisions. Such case-by-case mitigation packages could be a combination of the above mitigation provisions or could include beneficial arrangements for BPA that have not been addressed in this policy. Our main concern in any mitigation package is recovery of any spot-market revenue losses, but we will also be looking at the operational impacts of any proposal.

Extraregional Access. Provisions in the 1987 draft for firm transactions by extraregional utilities required that the utility must provide some benefit to BPA, such as increased storage, improved system coordination or operation, or other consideration of value. In addition, the utility must agree to the mitigation provisions of the policy. Canadian utilities were required to wait for access until after the Intertie was rated at 7900 MW.

In reconsidering this provision we saw no reason for denying Canadian utilities access for firm transactions until after the Intertie is upgraded to 7900 MW if Canadian utilities are willing to provide increased coordination or other items of value. This provision of limiting Canadian access to after an upgrade of the Intertie has been deleted from the LTIAP.

As with Formula Allocation, BPA anticipates that if the Free Trade Agreement is passed the distinction between U.S. extraregional utilities and Canadian utilities will no longer exist.

FISH AND WILDLIFE PROTECTION

Protected Areas. The LTIAP prohibits Intertie access for new hydro projects licensed within "protected areas" -- river reaches withdrawn from hydro development due to the presence of wildlife or anadromous and high-value resident fish. BPA also has designated areas where we have determined that investments in habitat, hatchery, passage, or other projects may result in the presence of anadromous fish. The Northwest Power Planning Council (Council) has proposed a protected area program that covers the entire Northwest. BPA's designations, however, cover only the Columbia River basin.

Our focus is on hydro developments which will frustrate our investments made in the region to achieve the goals of the Council's Fish and Wildlife Program. The LTIAP ensures that those expenditures and existing productive habitat will not be harmed by future hydro developments. BPA has designated protected areas by using information collected through the Council's Hydro Assessment Study.

Under the LTIAP, we will consider the Council's final protected area program or any revisions the Council may include in the future. We will also consider appropriate state comprehensive river plans. The policy should effectively eliminate utilities' fears that they never know with certainty whether a hydro resource will qualify, or continue to qualify, for access to the Intertie.

The LTIAP does not necessarily prevent hydro development in protected areas. However, the protected area provisions will send an unambiguous, self-enforcing message to FERC, other regulators, and hydro developers that no Intertie access will be provided for projects constructed in areas of greatest concern to BPA and the Council.

Enforcement. If a Scheduling Utility proceeds to acquire a license or purchase power from a hydro project developed in a protected area, BPA will reduce the amount of that utility's power transmitted over the Intertie during Condition 1. Depending upon the size of the project, the reduction may affect both Assured Delivery and Formula Allocations. These reductions will take place regardless of whether power from the protected area project is actually transmitted on the Intertie. There is no need to trace power flows from a protected area resource.

Projects not affected by the Policy. For all hydro projects not affected by BPA's protected area designations, BPA will intervene in FERC proceedings if we determine that projects -- new or existing, inside or outside the Columbia Basin -- pose significant threats to our fish and wildlife responsibilities.

The provisions do not affect hydro projects licensed before the effective date of the policy. While we recognize a potential for existing projects to harm BPA fish and wildlife investments, we do not believe there is sufficient evidence to indicate that those projects are presently operating contrary to

the Council's Fish and Wildlife Program or that the Council has been unable or unwilling to implement Program measures through the FERC process. Measures affecting existing projects in the Council's Program are explicitly directed to FERC and state agencies for implementation.

We have provided a limited procedure to provide access to the Intertie in the case of a project a developer believes will contribute to the Council's Fish and Wildlife Program and BPA investments. However, our decision to provide access relies on a clear demonstration of the benefits and a regional consensus.

Finally, the LTIAP creates a limited exception for Protected Area projects that an investor-owned utility might be forced to acquire under PURPA. To qualify, however, the affected utility must pursue all legal remedies available to avoid purchasing the Protected Area project output.

LONG-TERM INTERTIE ACCESS POLICY

GOVERNING TRANSACTIONS OVER FEDERALLY OWNED
PORTIONS OF THE
PACIFIC NORTHWEST–PACIFIC SOUTHWEST INTERTIE

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

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FINAL LONG-TERM INTERTIE ACCESS POLICY

Section 1. **Definitions**

1. "Administrator" means the Administrator of Bonneville Power Administration (BPA) and is used interchangeably with BPA.

2. "Administrator's Power Marketing Program" refers to all marketing actions taken and policies developed to fulfill BPA's statutory obligations. These actions and policies are based on exercises of authority to act, consistent with sound business principles, to recover revenue adequate to amortize investments in the Federal Columbia River power and transmission systems, while encouraging diversified use of electric power at the lowest practical rates. In the Northwest, the Administrator's Power Marketing Program covers BPA's obligations to provide an adequate, reliable, economical, efficient, and environmentally acceptable power supply, while preserving public preference to Federal power. In the Southwest, the Administrator's Power Marketing Program covers activities to market surplus Federal power at equitable prices, while preserving regional and public preference to Federal power, and to assist in marketing Northwest nonfederal power.

3. "Allocation" means the share of the Intertie Capacity made available for short-term sales of energy.

4. "Assured Delivery" means firm transmission service provided by BPA under a transmission contract to wheel power covered by a contract between a Scheduling Utility and a Southwest utility. Assured Delivery contracts may not exceed 20 years in duration. The service is interruptible only in the event of an uncontrollable force or a determination made pursuant to sections 7 or 8 of this policy.

5. "Available Intertie Capacity" is defined as the physically available capacity controlled by BPA, reduced by the capacity reserved under Section 2 of this policy, and the capacity necessary to satisfy Assured Delivery contracts not subject to operational mitigation requirements under this policy.

6. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts; and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act.

7. "Exchange" refers to various types of transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power, at prespecified delivery rates, from North to South during the Southwest's peak demands and returns of capacity and/or energy from South to North during other times. Transactions vary depending on the lag between deliveries and returns. A "naked capacity" transaction might require off-peak energy returns within 24 hours, whereas a seasonal exchange might call for firm power returns within 6 months.

8. "Extraregional Utilities" are generating utilities, or divisions thereof, that do not provide retail electric service and do not own or operate significant amounts of generating capacity in the Northwest.

9. "Formula Allocation" means the process by which Intertie Capacity made available for short-term sales of energy.

10. "Intertie" means the two 500-kv alternating current (AC) transmission lines and one 1000 kv direct current (DC) line, which extend from Oregon into California or Nevada, and any additions thereto identified by BPA as Pacific Northwest-Pacific Southwest Intertie facilities.

11. "Intertie Capacity" means the North to South transmission capacity of the Intertie controlled by BPA through ownership or contract; increased by power scheduled South to North, decreased by loop flow, outages, and other factors that reduce transmission capacity; and further decreased by Pacific Power & Light Company's schedules, under its scheduling rights at the Malin substation (BPA Contract Nos. DE-MS79-86BP92299 and DE-MS79-79BP90091).

12. "Mitigation" refers to the requirements imposed by BPA on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's firm power transaction, that inhibit BPA's ability to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless a scheduling utility either agrees to a specially designed charge or negotiates substitute measures with BPA on a case-by-case basis.

13. "Nonscheduling Utility" means a nonfederal Northwest utility that owns a Qualified Northwest Resource, but does not operate a generation control area within the Pacific Northwest. A Nonscheduling Utility requesting Intertie access for its resource must do so through the Scheduling Utility (or BPA) in whose control area the resource is located.

14. "Pacific Northwest" (or "Northwest") is defined in the Northwest Power Act, 16 U.S.C. §839e, as the states of Oregon, Washington, and Idaho; the portion of Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and any contiguous service territories of rural electric cooperatives serving inside and outside the Pacific Northwest, not more than 75 air miles from the areas referred to above, that were served by BPA as of December 1, 1980.

15. "Protected Area" means a stream reach within the Columbia River drainage basin specially protected from hydroelectric development because of the presence of anadromous or high value resident fish, or wildlife. Protected areas may also include stream reaches which could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

16. "Qualified Extraregional Resource" means:

(a) a generating unit located outside the Northwest that was in commercial operation on the effective date of this policy. However, the term excludes portions of units covered as Qualified Northwest Resources.

(b) after BPA has determined that the capacity of the Intertie is rated at approximately 7,900 MW, all resources located outside of the Northwest, other than the portions of extraregional resources covered as Qualified Northwest Resources.

17. "Qualified Northwest Resource" excludes BPA Resources, but includes:

(a) Resources located inside the Northwest that are in commercial operation as of the effective date of this policy.

(b) Scheduling Utility extraregional generating resources dedicated to Northwest loads on the effective date of this policy. This term includes pro rata portions of Montana Power Company's and Pacific Power and Light Company's shares of the Colstrip No. 4 generating station, based on the ratio of their respective regional loads to their respective total loads; and Idaho Power Company's share of Valmy No. 2.

(c) New regional resources of Scheduling Utilities, except for hydroelectric resources located in Protected Areas.

18. "Resource" means an electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

19. "Scheduling Utility" means the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The term excludes Utah Power & Light Company, either as a separately owned company or as a division of another corporation, which has sufficient transmission capacity to the Southwest without access to the Federal Intertie.

20. "Seasonal Exchange" means a transaction that takes advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power, at a prespecified delivery rate, from North to South during the Southwest's summer load season and from South to North during the Northwest's winter load season. Seasonal Exchanges may involve payments of additional consideration to reflect the relative seasonal values of power throughout the western United States. Seasonal Exchange schedules of Northwest utilities will be referred to as "deliveries," and schedules of Southwest utilities will be referenced as "returns." A Scheduling Utility must be able to support its summertime firm power deliveries with generating resources that are surplus to its Northwest requirements. The sum of a Scheduling Utility's energy resources for each month in which deliveries are made (with special concern for August) must exceed its corresponding Northwest loads by an amount sufficient to support the Seasonal Exchange.

21. "Section 9(i)(3) resource" means a Scheduling Utility resource that BPA has granted priority in receiving BPA transmission, storage and load factoring services as defined in §9(i)(3) of the Northwest Power Act.

Section 2. **Intertie Capacity Reserved for BPA**

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) transmit all of BPA's surplus firm power and to serve other obligations,

(b) perform obligations, including, but not limited to, the existing transmission contracts listed in Exhibit A, to the extent such obligations differ from the conditions specified in this policy,

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit B to this policy, and

(d) satisfy BPA firm obligations, that have not been prescheduled, by using unutilized portions of Formula Allocation amounts.

Section 3. **Conditions For Intertie Access**

(a) All Intertie access will be granted pursuant to the conditions and procedures of this policy, unless otherwise specified in the three existing BPA transmission contracts listed in Exhibit A.

(b) BPA will provide Intertie access only for BPA Resources and the Qualified Northwest Resources of Scheduling Utilities, except to the extent that Qualified Extraregional Resources are permitted access under this policy.

(c) BPA will provide Assured Delivery and allocate remaining Intertie Capacity when providing such access will not substantially interfere with operating limitations of the Federal system. Examples of these limitations, which reflect BPA's obligation to operate in an economical and reliable manner consistent with prudent utility practices, include:

(1) The BPA Reliability Criteria and Standards,
(2) Western Systems Coordinating Council minimum operating reliability criteria,
(3) North American Electric Reliability Council Operating Committee minimum criteria for operating reliability, and
(4) coordination agreements among BPA, scheduling utilities and other Federal agencies regarding resource and river operations.

(d) Any utility that has contractual or ownership rights to Pacific Northwest-Pacific Southwest Intertie capacity or to other transmission lines to California or the Southwest market must fully utilize such capacity prior to receiving any access to BPA's Intertie Capacity. If a Scheduling Utility with Intertie rights needs BPA Intertie Capacity to reach a particular Southwest utility, BPA will consider negotiated swaps of capacity to accommodate such requests.

Section 4. **Assured Delivery for Intertie Access**

Subject to the limitations and other conditions in this section and in other sections of this policy, BPA has determined that it can provide limited Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) **General Provisions**

(1) **Existing Transmission Contracts.** BPA will provide Assured Delivery for the remaining terms of the firm power sale and Seasonal Exchange contracts identified in Exhibit A to this policy.

(2) **Utilities Owning Or Controlling Southwest Interconnections.** Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. Except for transactions covered by section 4(b) of this policy, a utility with capacity on an intertie, through contract or ownership, must utilize all such capacity on a firm basis before receiving any Assured Delivery.

(3) **Nature Of Transactions.** BPA will not provide Assured Delivery for transactions which a Scheduling Utility cannot demonstrate to be other than an advance arrangement to sell nonfirm energy.

(4) **Waiver Of BPA Service Obligation.**

(A) **Hydroelectric Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest hydroelectric energy shall provide, under 16 U.S.C. §837b(d), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided .

(B) **Thermal Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest thermal energy shall provide, under 16 U.S.C. §839f(c), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided. Such reduction shall become effective at the time BPA determines that it has reached energy load/resource balance, or at a date as specified in the Assured Delivery contract.

(5) **Exchange Contracts.** Exchange contracts must specify that all return energy be scheduled to either the AC Intertie point of interconnection at the California-Oregon border ("COB") or the DC Intertie point of interconnection at the Nevada-Oregon border ("NOB"). Exchange contracts must also specify prescheduled determinations of hourly energy returns.

(6) **Satisfying Requests For Assured Delivery.** All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made.

(b) **New Transactions Not Subject To Capacity Limits**

(1) **Joint Ventures.** Joint ventures between BPA and utilities, such as firm displacement contracts, which allow BPA to increase its sales of surplus power qualify for Assured Delivery.

(2) **Sales In Lieu Of Exchanges.** BPA may offer to satisfy Scheduling Utility demands for Seasonal Exchanges by selling them incremental amounts of surplus firm power during winter months. Upon committing to purchase such incremental firm power at negotiated prices that reflect BPA's

lost opportunities for summer sales, a Scheduling Utility will qualify for Assured Delivery (with mitigation) to wheel an equal amount of firm capacity and energy over the Intertie during summer months.

(3) **Conditions**. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(b)(1) and 4(b)(2). Relevant contracts must be presented for review when Assured Delivery is requested. BPA will satisfy a request within 60 days after a Scheduling Utility has demonstrated satisfaction of the requirements of this policy.

(c) **Transactions Subject To Capacity Limits Under This Policy**

(1) **Maximum Amounts Of Assured Delivery**. BPA will provide 800 MW of Assured Delivery for firm power sales and Exchanges identified in this policy. BPA will reassess the amount of Assured Delivery capacity when the 3d AC Intertie project is either completed or abandoned. Moreover, the 800 MW amount may be subject to some reduction if the DC Terminal Expansion project is not completed on schedule.

(2) **Exhibit B amounts**.

(A) **Current maximum**. Each Scheduling Utility's maximum Assured Delivery amount for firm sales equals its average firm energy surplus, shown in Exhibit B to this policy. BPA will reserve capacity equal to each Scheduling Utility's Exhibit B allocation subject to section 4(c)(2)(D) below. Except for Montana Power Company (MPC), Tacoma City Light, and Cowlitz County Public Utility District, Exhibit B represents projected Scheduling Utility surpluses for the 1988-89 operating year. In satisfaction of all obligations to MPC under Northwest Power Act section 9(1)(3), MPC's Exhibit B amount is set at 105 MW to facilitate long-term sales of firm power from its share of the Colstrip No. 4 coal-fired generating station. Exhibit B amounts for Tacoma and Cowlitz are increased to accommodate existing firm power transactions.

(B) **Shaping**. Firm power sales eligible for Assured Delivery may be shaped within the following ranges. During the months of September through December, a Scheduling Utility may deliver firm energy at a rate up to 1.8 times its Exhibit B average firm surplus amount. During the months of January through August, a Scheduling Utility may deliver firm energy at a rate no greater than 1.0 times its Exhibit B amount. However, total delivered energy may not exceed the Exhibit B annual firm energy maximum.

(C) **Other uses of Exhibit B amounts**. BPA will not entertain Assured Delivery requests for firm power sales in excess of a utility's Exhibit B maximum. However, a Scheduling Utility may use any portion of its Exhibit B maximum, not used for firm power sales, for exchange transactions supported by Qualified Northwest Resources.

(D) **Future changes**. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount will be revoked if, upon revision, a utility's individual Exhibit B amount has declined or if a utility has sold firm power to another utility seeking to increase its Exhibit B

average firm surplus amount. A Scheduling Utility may increase its individual Exhibit B amount by purchasing surplus firm power from BPA or any Scheduling Utility with an Exhibit B amount.

(3) **Other Capacity**. The remaining capacity available for Assured Delivery under this policy is offered to Scheduling Utilities, on a first-come, first-served basis, for Exchange transactions supported by Qualified Northwest Resources. When section 4(c)(2)(D) of this policy is implemented to reduce the Exhibit B maximum of any Scheduling Utility, the reduction will be added to the capacity made available under this provision. Any utility with an Exhibit B amount must exhaust such capacity before requesting Assured Delivery under this provision.

(d) **Mitigation**

(1)**Operational Mitigation**

(A) **Southbound deliveries**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures to preschedule energy deliveries, each utility's Assured Delivery amount shall be deducted from its formula allocation to determine its share of energy scheduled on the Intertie. If the remainder is negative for a given utility, then that utility must make up the difference by purchasing sufficient energy as follows:

(i) during Condition 1 from BPA or any Scheduling Utility with a Formula Allocation during that hour;

(ii) during Condition 2 from BPA, however, if BPA is not in the market the utility may purchase sufficient energy from any other utility.

(B) **Northbound returns**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures, a utility may utilize the cash-out provisions of an Exchange contract only by reducing one-for-one the amount of North-to-South Intertie capacity otherwise available to it under this policy. The rate of cash out during any condition shall not exceed the rate at which the exchange return could have been scheduled.

(2) **Negotiated mitigation**. A Scheduling Utility may also elect to negotiate with BPA on a case-by-case basis a package of mitigation measures involving mutually agreeable consideration of value commensurate with the service provided.

Section 5. **Formula Allocation Methods**

(a) **Limits On Intertie Capacity Available For Formula Allocation**. Generally, BPA will determine Intertie Capacity available for Formula Allocations after first taking into account the amount of Intertie Capacity necessary to satisfy requirements of the Administrator's Power Marketing Program, existing transmission contracts listed in Exhibit A, and Assured Delivery contracts executed by BPA pursuant to this policy. However, in determining Available Intertie Capacity during Condition 1, BPA will not consider the Assured Delivery contracts to the extent they are subject to operational mitigation requirements. BPA may reduce any allocation, if additional Intertie Capacity is required to minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.

(b) **Protected Area Decrements**. Except as provided in section 4(d)(2)(A) of this policy, BPA will reduce each Scheduling Utility's allocation by any Protected Area decrement imposed pursuant to section 7(d).

(c) **Allocation Methods**.

(1) **Condition 1**

(A) **Until December 31, 1988**. Intertie Capacity will be allocated pursuant to the Exportable Agreement (BPA Contract No. 14-03-73155), when applicable.

(B) **After December 31, 1988**. Condition 1 will be in effect when the Federal hydro system is in spill or there is a likelihood of spill, as determined by BPA. Available Intertie capacity will be allocated pursuant to the following procedure:

(i) Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective declarations to total declarations, multiplied by the Available Intertie Capacity.

(ii) During Condition 1, whenever BPA is unable to utilize its full pro rata share of intertie usage BPA will take larger allocations on ensuing days until the difference in pro rata intertie usage is eliminated.

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, Formula Allocations for BPA and each Scheduling Utility will approximate, by hour, the ratio of each declaration to the sum of all declarations, multiplied by the available Intertie capacity.

(B) If BPA sales drop below 75 percent of its allocation during Condition 2, BPA may take larger allocations on ensuing days until the difference is eliminated.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA and Scheduling Utilities' allocations will equal their declarations. The remaining Intertie capacity will be made available first to U.S. Extraregional Utilities and then to other Extraregional Utilities. Section 3(d) of this policy shall not apply to Scheduling Utilities during Condition 3.

(d) **Formula Allocation Experiment**. BPA is interested in exploring the proposal that it cease making individual Formula Allocations to Scheduling Utilities under Conditions 2 and 3. However, BPA must work with Northwest and Southwest utilities to develop the information capability to accommodate a new scheduling system for nonfederal access. As soon as this can be accomplished BPA will substitute the following provisions for section 5(c) on an 18-month experimental basis:

(1) **Condition 1**

Same as section 5(c)(1).

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, the Formula Allocation for BPA will approximate, by hour, the ratio of BPA's declaration to the sum of all declarations, multiplied by the Available Intertie Capacity. The remaining capacity will be made available as a block to Scheduling Utilities. Section 5(c)(2)(B) of this policy shall apply.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA's allocation will equal its declaration. The remaining Intertie capacity will be made available, first, as a block to satisfy the declarations of Scheduling Utilities, second, to U.S. Extraregional Utilities, and third to other Extraregional Utilities. Section 3(d) of this policy shall not apply during Condition 3.

(e) **Data Collection and Evaluation.** Commencing when this policy goes into effect and continuing during the course of the experiment described in section 5(d), BPA will collect information on the following topics relevant to future allocation procedures:

(1) effect on BPA revenue of allocating to nonfederal utilities as a group rather than individually.

(2) impairment of Intertie access for California utilities presently lacking ownership in the southern portion of the Intertie,

(3) any loss of sales to BPA due to a failure to share unused capacity among California entities with ownership or contractual interests in the Intertie,

(4) effects of the experiment on small Scheduling Utilities.

During the course of the experiment, interested parties may submit written comments and recommendations on these issues.

(f) **Findings and conclusions.** At least 30 days before the end of the experiment described in section 5(d), BPA shall publish a report of its findings on the experiment and its decision on whether section 5(d), with possible modification, should be continued as the permanent method of Formula Allocation.

Section 6. **Access for Qualified Extraregional Resources**

(a) **Assured Delivery.** Any request for Assured Delivery of power from a Qualified Extraregional Resource would be granted only by contract which, in addition to the Mitigation measures specified in section 4(d), must include

benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether they would cause substantial interference with the Administrator's Power Marketing Program. An environmental review would also be conducted.

(b) **Formula Allocation**. Under Condition 3, energy from Qualified Extraregional Resources has access to the Intertie. In addition, BPA may provide Extraregional Utilities with Formula Allocation under other conditions, if the utility agrees by contract either to increased participation in the Pacific Northwest's coordinated planning and operation, or to provide other consideration of value, apart from the standard BPA wheeling rate, commensurate with the services provided.

Section 7. **Fish and Wildlife Protection**

(a) **Purpose**. New hydroelectric projects constructed in Protected Areas may substantially decrease the effectiveness of, or substantially increase the need for, expenditures and other actions by BPA, under Northwest Power Act section 4(h), to protect, mitigate or enhance fish and wildlife resources. Intertie access will not be provided to facilitate the transmission of power generated by any new hydroelectric projects located in Protected Areas and licensed after the effective date of this policy. This provision does not apply to added capacity at existing projects.

(b) **Effect**. This section imposes automatic operational limitations on a utility by reducing the amount of energy that can be scheduled over the Intertie, thereby increasing costs or reducing revenues for any utility owning or acquiring the output of a Protected Area hydroelectric resource.

(c) **Implementation**. Protected Area designations for stream reaches in the Columbia River Basin are shown in Exhibit C to this policy. Exhibit C uses Environmental Protection Agency stream reach codes. Subject to review and possible modification, BPA will consider the adoption of comprehensive state watershed management plans and a comprehensive protected area program developed by the Pacific Northwest Electric Power and Conservation Planning Council subsequent to implementation of this policy. BPA will also consider revisions to Protected Area designations if the Council's Program is amended.

(d) **Enforcement**. If a Scheduling Utility or Nonscheduling Utility owns, or acquires the output from, a hydroelectric project covered under the restrictions of section 7(a), BPA will reduce that utility's Formula Allocation by either the nameplate rating of the project (in the case of ownership), or the amount of capacity acquired by contract.

(e) **Exceptions**.

(1) **PURPA Projects**. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an investor-owned utility has been compelled to acquire the output of a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act (PURPA). To qualify for this exception, the investor-owned utility must demonstrate:

(A) that it has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the Protected Area resource in question;

(B) that it has petitioned its state regulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources in recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy;

(C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and

(D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that it was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

(2) **Projects Contributing to Council's Fish and Wildlife Program or BPA Investments**. Access will be automatically denied for projects developed in protected areas unless BPA receives sufficient demonstration that a particular project will provide benefits to existing or planned BPA fish and wildlife investments or the Council's Program. BPA's determination will be based on:

(A) information provided by the project developer, Federal and state fish and wildlife agencies, and tribes; or

(B) action by the Pacific Northwest Power Planning Council.

Section 8. **Other Enforcement Provisions**

(a) Whenever the terms of this policy are not being met, BPA will inform the appropriate utility of the nature of the noncompliance and actions that may be taken to achieve compliance. If noncompliance is not corrected within a reasonable period, BPA may deny access for a resource and refuse to accept schedules.

(b) Upon approval of the proposed U.S.-Canada Free Trade Agreement by the Canadian Parliament and the United States Congress, any and all distinctions made in this policy between Canadian and United States Extraregional Utilities shall terminate on the effective date of the Agreement.

EXHIBIT A
EXISTING AGREEMENTS FOR INTERTIE CAPACITY

This is a list of existing BPA transmission contracts that were signed before the implementation of the NTIAP and will continue to receive Intertie access under the LTIAP.

Utility	BPA Contract No.	Expiration Date
Washington Water Power Company	DE-MS79-81BP90185	07/01/91
Washington Water Power Company	14-03-791101	09/01/88
Western Area Power Administration	DE-MS79-84BP91627	10/31/90

EXHIBIT B
INTERTIE CAPACITY AVAILABLE FOR ASSURED DELIVERY

BPA has reserved 800 MW of Intertie capacity to be available for nonfederal firm transactions. This capacity is allocated as follows:

A. Average Firm Surplus Allocations:

UTILITY	AVERAGE MW FIRM SURPLUS	
Chelan County PUD #1	10	
Cowlitz County PUD #1	45	1/
Douglas County PUD #1	0	2/
Eugene Water and Electric Board	14	
Grant County PUD #1	26	
Seattle City Light	23	
Snohomish County PUD #1	0	
Tacoma City Light	41	3/
Idaho Power Company	87	
Montana Power Company	105	4/
Puget Sound Power and Light	0	
Washington Water Power	93	
	444	

NOTE: The Average Firm Surplus (AFS) is directly from the PNUCC Northwest Regional Forecast of March 1987 for the period 1988-89 except as noted below. It includes resources operational on the effective date of this policy. Export contracts are included as loads. Utilities may use their AFS allocations for long term firm sales or for exchanges. Portland General Electric Company and Pacific Power & Light Company are not eligible for an AFS allocation because of their existing interconnections with the Southwest.

1/ Cowlitz Co. PUD's AFS is the amount of their existing export of the Longview Fibre resource. Longview Fibre is considered to be a Federal resource in the Northwest Regional Forecast and is not included under Cowlitz.

2/ Douglas County PUD's AFS is 2; but Douglas has previously requested to show zero.

3/ The amount displayed for Tacoma is the amount of their existing exports displayed in the Northwest Regional Forecast.

4/ Montana Power Company's AFS was increased from 80 MW to 105 MW in settlement of obligations under Northwest Power Act section 9(i)(3).

B. Intertie Capacity Available for Exchanges: The above allocations for sales of firm surplus may be used for exchanges. The remaining 356 MW of capacity is available on a first come-first serve basis for exchanges only under the terms of the LTIAP. If there is a decrease in a utility's firm surplus and the utility does not have a contract for that amount, BPA will allocate the difference to capacity available for exchanges by revising this Exhibit B.

EXHIBIT C
PROTECTED AREAS

Exhibit C corresponds to the Northwest Power Planning Council protected area designations within the Columbia Basin, as specified in the Columbia River Basin Fish and Wildlife Program. Stream reaches designated as protected areas are identified by Environmental Protection Agency stream reach codes. Information about designations are contained on hard copy computer printouts or computer diskette copies which are available to the public upon request.

This revision reduces the Transmission Demand from 125 MW to 93 MW on lines C.1.b. and C.2.b. due to implementation of the Capacity Ownership Agreement, Contract No. DE-MS79-95BP94628.

TRANSMISSION PARAMETERS

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1/]

1. North-to-South Transactions:

a.	01/01/94 to 05/31/94:	75 MW
b.	06/01/94 to 12/31/94:	125 MW
c.	01/01/95 and thereafter:	93 MW

2. South-to-North Transactions:

a.	01/01/94 to 05/31/94:	75 MW x Intertie South-to-North RTC ÷ 4800 MW
b.	06/01/94 to 12/31/94:	125 MW x Intertie South-to-North RTC ÷ 4800 MW
c.	01/01/95 and thereafter:	93 MW x Intertie South-to-North RTC ÷ 4800 MW

1/ Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Account Executive

Name Patrick G. McRae
(Print/Type)

Date January 11, 1995

PACIFICORP

By _____

Name Jerry D. Miller
(Print/Type)

Title Manager, Power System Services

Date January 23, 1995

(PMLAN-MPSM-W:\PMT\CT\94285c_1.DOC)

Contract No. DE-MS79-94BP94332

AC INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

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This AC INTERTIE AGREEMENT ("Agreement"), executed June 1, 1994, by the UNITED STATES OF AMERICA ("Government"), DEPARTMENT OF ENERGY, acting by and through the BONNEVILLE POWER ADMINISTRATION ("Bonneville") and PACIFICORP ("PacifiCorp"), a corporation organized and existing under the laws of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

W I T N E S S E T H:

WHEREAS the Parties have entered into the Transmission Agreement (Contract No. DE-MS79-79BP90091), as amended, which

hereinafter is referred to as "Midpoint-Medford Agreement"; and

WHEREAS the Parties have entered into the Intertie Agreement (Contract No. DE-MS79-86BP92299), as amended, which hereinafter is referred to as "Intertie Agreement"; and

WHEREAS the Parties have entered into an Agreement of Principles, dated May 28, 1993, which hereinafter is referred to as "Letter of Understanding" and which provides, among other things, for the revision of certain terms and conditions in the Midpoint-Medford Agreement and the Intertie Agreement; and

WHEREAS the Parties have entered into the Midpoint-Meridian Transmission Agreement (Contract No.DE-MS79-94BP94333) which hereinafter is referred to as "Midpoint-Meridian Transmission Agreement" which replaces and supersedes the Midpoint-Medford Agreement; and

WHEREAS the Parties desire to replace and supersede the Intertie Agreement with this Agreement; and

WHEREAS the Parties have entered into the AC Intertie Operation and Maintenance Agreement (Contract No. DE-MS79-93BP94278) which hereinafter is referred to as "AC Intertie O&M Agreement"; and

WHEREAS Bonneville and PacifiCorp are Parties to Contract No. 14-03-59840 ("Malin Substation Construction Agreement") which provides for rights and obligations regarding construction, operation, ownership and use of the Malin Substation and desire to continue such agreement for the term of this Agreement; and

WHEREAS PacifiCorp has constructed a 500 kV line from the interconnection with Bonneville at Alvey Substation to Meridian Substation ("Alvey-Meridian Line") to provide increased Load Carrying Capability; and

WHEREAS Bonneville has expanded the Rated Transfer Capability of the AC Intertie to approximately 4800 megawatts and has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line; and

WHEREAS PacifiCorp and Bonneville have acquired joint ownership in the Alvey-Meridian Line and related facilities as provided for in Amendatory Agreement No. 2 to the Intertie Agreement ("Payment Agreement"), Amendatory Agreement No. 1 to the Intertie Agreement ("Option Agreement") attached hereto as Exhibits A and D respectively and Exhibit B hereto; and

WHEREAS nothing in this Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Agreement;

NOW, THEREFORE, in the interest of resolving issues of AC Intertie rights and service to PacifiCorp's Load Area, now and in the future, Bonneville and PacifiCorp are entering into this Agreement to accomplish the following goals:

(a) To enable Bonneville's planning, construction, operation and maintenance of an AC Intertie with a bidirectional Rated Transfer Capability of approximately 4800 megawatts and to enable PacifiCorp's planning, construction, operation and maintenance of facilities to serve its Load Area.

(b) To permit the Parties' specified use of the Buckley-Alvey Loop in a manner that does not jeopardize reliable service on either Party's system.

(c) To limit PacifiCorp's right to use its own facilities to schedule power and energy from its Load Area to adjoining areas and to ensure that this right is exercised in a manner that does not reduce the Operational Transfer Capability of the AC Intertie.

(d) To facilitate joint development of facilities by Bonneville and PacifiCorp as specified in this Agreement.

(e) As between the Parties, to facilitate the economical development and fair allocation of any AC Intertie transfer capability above 4800 megawatts.

It is the intention of the Parties that this Agreement be implemented and interpreted to best effectuate the above stated goals. Where this Agreement makes reference to not unreasonably withholding consent or agreement, the reasonableness of each Party's position will be judged with reference to the above stated goals.

1. Term of Agreement. This Agreement shall be effective and shall supersede the Intertie Agreement in accordance with section 15 herein when executed by the Parties and accepted for filing or otherwise approved without change by the Federal Energy Regulatory Commission and shall terminate when all of the facilities comprising the AC Intertie are permanently taken out of service. Upon termination of this Agreement, all liabilities

accrued hereunder shall be and are hereby preserved until satisfied.

2. Exhibits. Exhibits A through E are incorporated as part of this Agreement. Revisions to the Exhibits shall be by mutual consent.

3. Plan-of-Service for AC Intertie.

(a) Bonneville's Right to Establish Plan-of-Service. PacifiCorp agrees that Bonneville alone shall have the right to establish any Plan-of-Service for upgrading the AC Intertie to approximately 4800 megawatts, provided such Plan-of-Service is in keeping with Prudent Utility Practice, and further provided such Plan-of-Service does not result in reducing PacifiCorp's Load Carrying Capability.

(b) PacifiCorp's Right to Comment. Bonneville shall provide PacifiCorp the opportunity to comment on any such Plan-of-Service Bonneville may establish.

4. AC Intertie Construction and Ownership up to Approximately 4800 Megawatts of Rated Transfer Capability

(a) Alvey-Meridian Line Rights. To achieve the upgrade of the AC Intertie to a Rated Transfer Capability of approximately 4800 megawatts, Bonneville has acquired a 50 percent undivided ownership right in the Incremental Capacity of the Alvey-Meridian Line which is jointly owned by Bonneville and PacifiCorp as provided for in the Payment Agreement and Exhibit B. For the term of this Agreement, Bonneville shall have the unrestricted right to use such ownership interest. Bonneville

may use such unrestricted right for purposes including, but not limited to, the interregional transfer of electric power, the integration of the electric power output of generation resources, and for service to the electric power loads of Bonneville's customers. Bonneville and PacifiCorp have shared, in accordance with the percentages specified in Exhibit B, the actual costs of facilities associated with construction of the Alvey-Meridian Line and other related additions. Unless otherwise stated in Exhibit B or in the AC Intertie O&M Agreement, Bonneville shall pay 42 percent and PacifiCorp shall pay 58 percent of the operation and maintenance costs of those facilities specified in Exhibit B. PacifiCorp shall bear all operation and maintenance costs for those facilities used exclusively to serve PacifiCorp's own loads. PacifiCorp and Bonneville shall act in good faith and use best efforts, including utilization of all reasonable legal remedies, to obtain and protect all necessary permits and licenses for the Alvey-Meridian Line.

(b) Captain Jack Substation. Bonneville has constructed and, except for those facilities which PacifiCorp owns pursuant to section 4(b)(3) herein, owns the Captain Jack Substation and the associated interconnection to COTP. Bonneville's ownership includes the land on which the substation and the interconnection are located. Bonneville has connected the Captain Jack Substation to PacifiCorp's 500 kV system between Meridian Substation and Malin Substation where the COTP

interconnects with the AC Intertie subject to the following terms, conditions and exceptions:

(1) Bonneville has constructed and owns terminal equipment, lines, and facilities required to interconnect the COTP with the Captain Jack Substation.

(2) Bonneville has constructed and owns the series and shunt compensation equipment and facilities located in the Captain Jack Substation required to connect to the COTP.

(3) PacifiCorp and Bonneville have shared equally in the cost of the bay 3 terminal equipment and facilities, which PacifiCorp owns, including the land on which such facilities are located, required to loop PacifiCorp's Malin-Meridian 500 kV line ("Malin-Meridian Line") into the Captain Jack Substation.

(4) PacifiCorp, at its expense and subject to Prudent Utility Practice, may install transformation equipment at the Captain Jack Substation. PacifiCorp agrees to provide Bonneville the one-line diagram and plot plan for the installation of transformation equipment in a timely fashion for inclusion in Bonneville's Plan-of-Service. Subsequent changes in the one-line diagram or plot plan of transformation equipment are subject to mutual consent.

(c) Modification of Facilities.

(1) Except in regard to the Malin Substation,

PacifiCorp agrees that it will make or permit Bonneville to make, at Bonneville's expense, any improvements or modifications of PacifiCorp's facilities in the Buckley-Alvey Loop that are required to accomplish Bonneville's Plan-of-Service. Unless otherwise mutually agreed, Bonneville shall own such improvements or modifications unless they cannot be removed without impairment or damage to PacifiCorp's facilities, in which case such modifications or improvements shall be jointly owned by Bonneville and PacifiCorp.

(2) AC Intertie Reactive Support. After joint studies have been completed and the Parties have mutually agreed that additional reactive support is required at the Malin Substation or Captain Jack Substation to support the AC Intertie, PacifiCorp shall be financially responsible for its share of the cost of such added reactive support.

(3) At such time as the Parties mutually agree, which agreement shall not be unreasonably withheld, that a second 500/230 kV transformer is required at the Malin Substation or a 500/230 kV transformer is required at the Captain Jack Substation, the Parties shall jointly develop the plan of service for such transformer(s). Each Party shall have the right to acquire up to a one-half ownership interest in such transformer(s) at a pro-rata share of cost, provided that PacifiCorp's Load Carrying Capability is not impacted. If a Party does not participate in the

ownership of such transformer(s) at the Malin or Captain Jack Substations at the time such transformer(s) are installed, such Party shall have the unilateral right to acquire up to a one-half ownership interest based on a pro-rata share of the original cost plus capital additions, if any, at a future date to the extent that capacity is available.

(4) Except as provided for in subsection 4(c)(1) herein, any improvements or modifications of the Buckley-Alvey Loop shall be by mutual consent, which consent shall not be unreasonably withheld. Except as provided for in subsections 4(c)(2) and 4(c)(3) above, installation of any equipment in the Malin Substation shall be made pursuant to the terms of the Malin Substation Construction Agreement.

(5) If Bonneville determines additions or modifications to the Alvey-Meridian Line are necessary to maintain the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie at 4800 megawatts, Bonneville may, by written notice, cause PacifiCorp to add such equipment or make such modifications, and Bonneville and PacifiCorp shall share equally in the costs and ownership of such additions and modifications unless otherwise mutually agreed. PacifiCorp and Bonneville shall share equally in any Incremental Capacity resulting from such modifications.

5. Rights of Use.

(a) Determination of AC Intertie Rated Transfer Capability and Operational Transfer Capability. PacifiCorp agrees that Bonneville may determine the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie, provided such determination is in keeping with Prudent Utility Practice, and further provided it does not have the effect of reducing PacifiCorp's ability to serve up to its Load Carrying Capability as specified in this section 5.

(b) Bonneville's Right to Use of PacifiCorp's Malin-Meridian Line. PacifiCorp shall provide Bonneville, at no charge, sufficient capacity in the Malin-Meridian Line for Bonneville's AC Intertie transactions for itself or on behalf of other parties to enable Bonneville to operate the AC Intertie at its Rated Transfer Capability. To the extent modifications in the Malin-Meridian Line are required to effectuate this subsection 5(b), the cost of such modifications shall be borne equally by Bonneville and PacifiCorp. PacifiCorp shall operate and maintain the Malin-Meridian Line to maintain the Rated Transfer Capability on the AC Intertie in keeping with Prudent Utility Practice.

(c) Bonneville's Rights and Obligations for Intertie Service. PacifiCorp agrees that Bonneville has the right to operate the AC Intertie up to its Rated Transfer Capability or Operational Transfer Capability, subject to the following terms and conditions:

(1) Subject to section 4(c)(2) herein, Bonneville shall provide reactive support to maintain the Rated Transfer Capability of the AC Intertie.

(2) Bonneville shall provide transmission reinforcement to maintain the Rated Transfer Capability of the AC Intertie.

(3) Bonneville shall not rate or operate the AC Intertie in a manner that interferes with PacifiCorp's use of its Load Carrying Capability as described in subsections 5(d)(1), 5(d)(2), and 5(d)(3) below. However, Bonneville may make use of PacifiCorp's unused Load Carrying Capability for AC Intertie transactions for itself or on behalf of other parties at no additional charge, except as otherwise provided in this Agreement.

(d) PacifiCorp's Rights and Obligations for Service to Load.

(1) Upon energization of the Alvey-Meridian Line, PacifiCorp shall have the right to serve PacifiCorp's Load Area and parallel paths, pursuant to section 10 herein, up to the Load Carrying Capability specified as follows:

(A) PacifiCorp shall have a Load Carrying Capability of 1875 megawatts.

(B) By the date when PacifiCorp's Load is expected to exceed the Load Carrying Capability recognized in subsection 5(d)(1)(A) herein, PacifiCorp shall provide additional facilities to supply power to its Load Area.

(2) The Load Carrying Capability specified in this subsection 5(d) may be correspondingly increased if new transmission facilities are constructed or if modifications are made to transmission facilities that increase the Load Carrying Capability. The effect of any such additions or modifications of transmission facilities on Load Carrying Capability shall be established by mutual agreement of the Parties using the results of joint planning studies conducted pursuant to subsection 5(d)(3) herein, and such mutual agreement shall not be unreasonably withheld.

(3) PacifiCorp's Load in its Load Area, and the date that such load is expected to exceed the Load Carrying Capability, shall be mutually determined by joint planning studies conducted annually, or as otherwise mutually agreed, by PacifiCorp and Bonneville in accordance with normal utility planning criteria. Such studies shall be based on mutually agreed to load forecasts for PacifiCorp's Load, as well as records of actual metered power flows on the then existing transmission lines serving the Load Area. PacifiCorp and Bonneville shall furnish any data reasonably required for the joint planning study.

(4) PacifiCorp shall provide reactive support and internal transmission reinforcement for PacifiCorp's Load, including, but not limited to, 500/230 kV transformation, and 230 kV and below transmission reinforcement. To the extent PacifiCorp fails to provide such reinforcements,

Bonneville shall not be obligated to reduce the Rated Transfer Capability or Operational Transfer Capability of the AC Intertie.

(5) Use of the Summer Lake Substation as a point of delivery by the Parties shall not impact PacifiCorp's Load Carrying Capability or Bonneville's usage of the AC Intertie.

(e) PacifiCorp's Scheduling Rights for AC Intertie Rated Transfer Capability in Excess of 4000 Megawatts. PacifiCorp's Southbound Scheduling Rights are 400 megawatts. PacifiCorp's Northbound Scheduling Rights shall equal 400 megawatts multiplied by a fraction whose numerator is the northbound Rated Transfer Capability of the AC Intertie and whose denominator is the southbound Rated Transfer Capability of the AC Intertie. PacifiCorp shall have the right to net its total northbound and southbound schedules under this Agreement. PacifiCorp agrees to cooperate with Bonneville in its efforts, if any, to secure a northbound AC Intertie Rated Transfer Capability of 4800 megawatts. PacifiCorp's Northbound Scheduling Rights and Southbound Scheduling Rights shall be subject to the following terms and conditions:

(1) To the extent PacifiCorp has unused Scheduling Rights available in any hour under this Agreement, such unused Scheduling Rights shall be available to Bonneville for AC Intertie transactions at no charge.

(2) Except as mutually agreed to, any net southbound

schedules by PacifiCorp in excess of Southbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the southbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie from John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Except as mutually agreed to, any net northbound schedules by PacifiCorp in excess of Northbound Scheduling Rights available to PacifiCorp pursuant to this subsection 5(e) and the northbound scheduling rights available to PacifiCorp pursuant to transmission agreements entered into in accordance with the Letter of Understanding, including future Pacific Northwest AC Intertie Capacity Ownership Agreements, shall be deemed to be transmitted over the AC Intertie to the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville. Such excess schedules shall be subject to Bonneville's then effective Long-Term Intertie Access Policy, PacifiCorp's rights under other agreements, and the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. In the event that PacifiCorp's net northbound/southbound schedules exceed PacifiCorp's scheduling rights as described above,

Bonneville shall provide transmission services to PacifiCorp pursuant to the same policies and rates that are generally applicable to Bonneville's other regional utility customers.

(3) If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin 500 kV line ("Midpoint-Malin Line"), the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to use its net Southbound Scheduling Rights available to it, any increment above the combined capability of such facilities shall be deemed to be transmitted from the John Day Substation, or any other AC Intertie delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Net Northbound Scheduling Rights shall be deemed to be delivered to PacifiCorp at Malin Substation or Captain Jack Substation. If insufficient capacity exists in the combined capability of PacifiCorp's Midpoint-Malin Line, the Malin-Meridian Line, and the Alvey-Meridian Line for PacifiCorp to integrate deliveries associated with its net Northbound Scheduling Rights available to it, any increment in excess of PacifiCorp's Load that can be served using the combined capability of PacifiCorp's facilities still in service shall be deemed to be transmitted from the Malin Substation to the John Day Substation, or any other AC Intertie

delivery point subsequently established by Bonneville, and shall be subject to the IS-93 Rate Schedule, or its successor, plus losses applicable to the AC Intertie. Transmission service over the Federal Transmission System shall carry charges and losses as specified in the Midpoint-Meridian Transmission Agreement.

(4) During times when the southbound AC Intertie Operational Transfer Capability is less then the southbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net southbound scheduling rights at Malin Substation and Captain Jack Substation as described herein shall be an amount determined by multiplying the southbound Operational Transfer Capability of the AC Intertie by the ratio of 400 megawatts to the southbound Rated Transfer Capability of the AC Intertie. During times when the northbound AC Intertie Operational Transfer Capability is less then the northbound AC Intertie Rated Transfer Capability, PacifiCorp's reduced net northbound scheduling rights shall be an amount determined by multiplying the northbound Operational Transfer Capability of the AC Intertie by the ratio of the Northbound Scheduling Rights to the northbound Rated Transfer Capability of the AC Intertie.

(f) Additional PacifiCorp Wheeling Rights. Until December 31, 2023, during Off-Peak Hours when PacifiCorp's northbound scheduling capability is less than 582 megawatts, Bonneville will provide PacifiCorp the right to utilize Bonneville's unused

northbound capability on the AC Intertie and the DC Intertie at the IS-A Rate, or its successor rate, so as to provide PacifiCorp with a total northbound scheduling capability of 582 megawatts. For the purposes of this subsection 5(f), PacifiCorp's northbound scheduling capability for any hour shall equal the sum during such hour of its Northbound Scheduling Rights hereunder and its northbound scheduling rights under the AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285, including rights under Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Bonneville's unused AC Intertie capability and DC Intertie capability shall be deemed to be capability not required to satisfy Bonneville's firm contractual commitments, as determined by Bonneville. PacifiCorp shall use best efforts to provide Bonneville advance notice of its desire to utilize its rights pursuant to this subsection 5(f). To the extent possible, such notice shall be provided at the time that PacifiCorp submits its preschedules to Bonneville pursuant to section 7 herein, provided, however, that PacifiCorp's failure to provide such notice with preschedules shall not diminish in any way, PacifiCorp's rights under this subsection 5(f).

(g) Remedial Action Schemes. PacifiCorp shall be responsible for providing or assuring, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and Operational Transfer Capability of the AC Intertie either

northbound or southbound. In support of its obligations to provide generator dropping for its net southbound AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on line at the time of a remedial action scheme requirement. Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net southbound AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on line at the time of a remedial action scheme requirement at no cost. To the extent PacifiCorp does not have the capability on line to provide generator dropping from its Mid-Columbia rights for its net southbound AC Intertie schedules, Bonneville shall, to the extent it has available on line generation, provide generator dropping capability to PacifiCorp at no cost. In the event that PacifiCorp no longer has rights to Mid-Columbia generation, PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the Rated Transfer Capability and the Operational Transfer Capability of the AC Intertie either northbound or southbound shall not be diminished. In support of PacifiCorp's net northbound AC Intertie schedules or its northbound DC Intertie schedules, PacifiCorp shall be responsible for making arrangements for any load dropping requirements. To the extent possible, as determined by Bonneville, Bonneville shall offer to sell remedial action scheme service to PacifiCorp to enable

PacifiCorp to meet its obligations pursuant to this subsection 5(g).

(h) PacifiCorp shall provide Bonneville firm capacity in the existing 500/230 kV transformer at the Malin Substation at a use-of-facilities rate for Bonneville's firm requirements, provided such capacity will be made available to Bonneville only after PacifiCorp has determined that it has the capacity necessary to meet its own requirements and provided further, that Bonneville's right to use the existing Malin transformer shall be limited to 200 megawatts.

6. Upgrades of the AC Intertie Above Planned Rated Transfer Capability of 4800 Megawatts. After Bonneville has determined that the southbound or northbound AC Intertie Rated Transfer Capability is at least 4800 megawatts, but not more than 4900 megawatts, Bonneville and PacifiCorp agree that if any additions or changes to the Buckley-Alvey Loop or other jointly-owned facilities are required to increase the Rated Transfer Capability of the AC Intertie, such additions or changes shall be by mutual consent of the Parties hereto, which consent shall not be unreasonably withheld. Bonneville and PacifiCorp shall have the right, but not the obligation, to participate equally in such increase in the AC Intertie Rated Transfer Capability resulting from such additions or changes, and, if they do so, each shall share equally in the costs of such additions or changes to the Buckley-Alvey Loop or other jointly owned facilities required for such increases.

7. Scheduling.

(a) Bonneville and PacifiCorp shall schedule through the Joint Intertie Scheduling Office all schedules with southwest entities at the Malin and Captain Jack Substations.

(b) Upon Bonneville's request, PacifiCorp shall notify the Joint Intertie Scheduling Office each recognized workday of the planned schedules over PacifiCorp's parallel facilities, as described and limited in section 10 herein, for the following day or days. PacifiCorp shall also provide Bonneville's schedulers with all preschedule modifications prior to the hour of such schedules in accordance with Bonneville's standard scheduling practices.

8. Losses. The Parties shall be compensated for electric power losses pursuant to Calculation of Losses as shown in Exhibit E. Such compensation shall be based upon an equitable allocation of the Parties' control area losses associated with this Agreement and with the Midpoint-Meridian Transmission Agreement (Contract No. DE-MS79-94BP94333). The loss allocation specified in Exhibit E shall be reviewed at least every five years, but a review may be requested by either Party annually. The loss allocation shall be reviewed by the Parties to reflect any changes to the loss allocation.

9. Waivers. Except as specified in this Agreement and the Letter of Understanding, PacifiCorp waives any claim to any ownership share or right to use the AC Intertie Rated Transfer Capability or to additional scheduling rights based on its

ownership in: (1) existing facilities as such facilities may be modified or (2) the Alvey-Meridian Line.

10. Construction and Operation of Parallel Facilities.

(a) PacifiCorp's right to construct and right to operate existing and new interconnections with Pacific Gas & Electric Company or other utilities adjoining PacifiCorp's service territory in southern Oregon and northern California in parallel with the AC Intertie shall be subject to the following terms and conditions:

(1) The interconnection shall operate at 230 kV or below and shall include a phase shifter, unless the Parties mutually agree that a phase shifter is not required.

(2) On any given hour the sum of PacifiCorp's Load and the schedule on the parallel path shall not exceed the Load Carrying Capability.

(3) Except as provided in subsection 10(c) herein, PacifiCorp's total Rated Transfer Capability on such interconnections shall not exceed 400 megawatts. The total Rated Transfer Capability on such interconnections shall include the 100 megawatt Cottonwood Interconnection with Pacific Gas and Electric Company. The Operational Transfer Capability on such interconnections shall never exceed the Rated Transfer Capability on such interconnections.

(4) PacifiCorp shall schedule as provided in subsection 7(b) herein. In no case shall such schedules exceed the Operational Transfer Capability of such

interconnections.

(5) PacifiCorp shall make available to Bonneville telemetry of the actual power flow over PacifiCorp's parallel path interconnections.

(6) Construction or operation of such interconnections shall not reduce or adversely impact the Operational Transfer Capability of the AC Intertie. If Bonneville determines the operation of any such interconnection reduces or impacts the Operational Transfer Capability of the AC Intertie on any hour, and AC Intertie users have need of additional Operational Transfer Capability on the AC Intertie, upon Bonneville's request PacifiCorp shall reduce schedules to the extent needed to eliminate such impact. PacifiCorp shall not be required to reduce schedules on the parallel paths if the Operational Transfer Capability of the AC Intertie is reduced as a result of outages on the AC Intertie.

(b) Except as provided in subsection 10(c) herein, PacifiCorp shall not construct, participate in, or allow new interconnections for any 345 kV or above transmission lines or facilities from any point on PacifiCorp's system in Oregon to the existing two Malin-Round Mountain-Table Mountain 500 kV lines or the COTP north of Table Mountain.

(c) Notwithstanding the provisions of subsections 10(a)(3) and 10(b) herein, PacifiCorp may (i) construct and operate existing and new interconnections, as referenced in subsection

10(a)(3) herein with Rated Transfer Capability in excess of 400 megawatts, and/or (ii) construct, participate in, and allow new interconnections as referenced in subsection 10(b) herein, if:

(1) such increase in Rated Transfer Capability or new interconnection is needed for PacifiCorp to meet good faith third-party requests for transmission service; and

(2) Bonneville has declined to provide, or lacks transmission facilities to provide, the requested transmission service; and

(3) such actions do not reduce the Rated Transfer Capability of the AC Intertie.

11. Wheeling From Palo Verde. For a period coincident with the term of PacifiCorp's March 23, 1993 Transmission Service Agreement ("TSA") with Southern California Edison Company ("SCE"), PacifiCorp, on hours that PacifiCorp does not require all or a portion of its transmission capacity rights pursuant to the TSA, shall offer Bonneville a first right of refusal to utilize such excess transmission rights under the TSA. PacifiCorp shall have sole discretion to determine whether it is making use of its TSA transmission rights. If Bonneville exercises its right to use PacifiCorp's TSA transmission rights, Bonneville shall reimburse PacifiCorp for SCE's charges to PacifiCorp for such usage. Such reimbursement shall be based upon PacifiCorp's then-effective transmission demand charges from SCE under the TSA which shall initially be $4.00 per megawatt-hour. If Bonneville exercises its first right of

refusal to utilize PacifiCorp's excess TSA transmission rights, Bonneville shall use its own AC Intertie or DC Intertie scheduling capability to accept and transmit power and energy scheduled under this section 11. Additionally, the exercise of such access by Bonneville shall not preclude PacifiCorp from utilizing its transmission rights acquired from Bonneville on the AC Intertie or the DC Intertie.

12. Summer Storage and Spring Energy Option

(a) Summer Storage. For a period of 20 years commencing with the effective date of this Agreement, PacifiCorp shall accept and store energy for Bonneville during the months of June and July of each year, provided that PacifiCorp is not required to reduce generation from its thermal plants to accept such energy. Bonneville shall provide PacifiCorp notice as to the amount of energy Bonneville desires to have stored one-week prior to the beginning of each month that Bonneville will deliver energy to be stored by PacifiCorp. Energy to be stored pursuant to this subsection 12(a) shall be delivered to PacifiCorp at the points of delivery specified in Exhibit C of the Short-Term Surplus Firm Capacity Sales Agreement (Contract No. DE-MS79-92BP93757), as amended or superseded, or such other points as may be mutually agreed to. PacifiCorp may, but shall not be required to, accept more than 100,000 megawatt-hours per month for storage and Bonneville shall deliver no less than 25,000 megawatt-hours per month for storage. Bonneville shall deliver energy to PacifiCorp for storage prior to entering into

the market to sell surplus energy. Unless otherwise mutually agreed, the hourly rate of delivery shall be determined by dividing the total energy to be stored in the month by the number of hours in such month. Except in times of system emergency, Bonneville shall adhere to the agreed-upon schedule of deliveries. PacifiCorp shall return stored energy to Bonneville during the months of September, October and November of each year in which energy was delivered to PacifiCorp. Unless otherwise mutually agreed, the hourly rate of return of the energy to Bonneville shall be determined by summing the total energy delivered to PacifiCorp during the prior June and July period, dividing such sum by three (3) and dividing the result by the number of hours in the month in which the energy is to be returned to Bonneville. Except during times of system emergency, PacifiCorp shall adhere to this hourly return schedule. Except when prevented by constraints on the Parties' transmission systems, including both operational and scheduling constraints, returned energy in any hour shall be delivered to Bonneville at the Hot Springs Substation, at an amount not to exceed 110 MW unless otherwise mutually agreed to, Summer Lake Substation or other mutually-agreed upon points of delivery. Storage provided pursuant to this subsection 12(a) shall be at no charge to Bonneville.

(b) Spring Energy Option. For a period of 20 years following the effective date of this Agreement, if requested by Bonneville, PacifiCorp shall deliver to Bonneville during Off-

Peak Hours, at the Hot Springs Substation, or other mutually-agreed points of delivery, up to 50,000 megawatt-hours during the month of March of each such year. The maximum rate of delivery for such energy shall be 200 megawatts per hour. To exercise its option to take such energy, Bonneville shall notify PacifiCorp by February 15 of each year as to the amount of energy Bonneville desires to have delivered during the following March. Except in times of system emergency, PacifiCorp shall deliver such energy in accordance with Bonneville's request, subject to the limitations of this subsection 12(b). Bonneville shall return the energy delivered by PacifiCorp during the following June 1 through July 15 period during Off-Peak hours at an hourly rate of delivery determined by dividing the amount of energy delivered by PacifiCorp during the previous March by the number of Off-Peak Hours in the June 1 through July 15 period or such other hourly rate of delivery as mutually agreed to. Such March Energy shall be returned to PacifiCorp at points of delivery as specified in Exhibit C of Contract No. DE-MS79-92BP93757 or such other points of delivery as are mutually agreed.

13. Sale or Assignment.

(a) This Agreement shall inure to the benefit of, and shall be binding upon, the respective successors and assigns of the Parties to this Agreement.

(b) PacifiCorp and Bonneville agree not to sell, assign, lease, sublease, or otherwise transfer this Agreement or any

interest therein, without the written consent of the other Party, such consent not to be unreasonably withheld. PacifiCorp and Bonneville also agree not to sell, assign, lease, sublease, or otherwise transfer any direct or indirect interest in the Malin Substation, the portion of the Midpoint-Malin Line between Summer Lake Substation and Malin Substation ("Summer Lake-Malin Line"), the Malin-Meridian Line, or the Alvey-Meridian Line, without the written consent of the other Party, such consent not to be unreasonably withheld, provided, however, that PacifiCorp's interest in such facilities may be conveyed to its respective trustees as security under a mortgage or deed of trust to secure indebtedness without such written consent, provided that each such trustee may act with respect to such interest only to the extent and in the manner that such act would have been authorized under this Agreement.

(c) If Bonneville or PacifiCorp is acquired in total by other entities, subsection 13(b) shall not apply to such acquisition.

14. Extension of Existing Agreements. The Parties agree that the termination dates of the Midpoint-Meridian Transmission Agreement, the Malin Substation Construction Agreement and all agreements related to joint ownership or interconnection on the Buckley-Alvey Loop, including but not limited to arrangements for the operation and maintenance of new facilities, shall be coincident with the termination date of this Agreement. The Payment Agreement and the Option Agreement are attached hereto

as Exhibits A and D respectively and made a part of this Agreement. The Payment Agreement and the Option Agreement provide for, among other things, certain construction, payment, ownership, operation and maintenance activities in progress at the time of execution of this Agreement. As these activities are completed or superseded by future agreements, PacifiCorp and Bonneville may agree to terminate some or all of the Payment Agreement and the Option Agreement provisions. To the extent any provisions of the Payment Agreement or the Option Agreement are in conflict with this Agreement, the terms and conditions of this Agreement shall prevail.

15. Termination of Agreement. The Parties agree that this AC Intertie Agreement supersedes and terminates in its entirety the Intertie Agreement, Contract No. DE-MS79-86BP92299, provided, however, that any liabilities incurred thereunder are hereby preserved until satisfied.

16. Execution of Other Agreements. The Parties agree to negotiate in good faith and execute construction agreements, operation and maintenance agreements, transmission agreements, and other such agreements that may be required to implement the provisions of this Agreement.

17. Arbitration. In the event of any dispute related to rights or obligations of the Parties, or satisfaction thereof, under this Agreement, including but not limited to the amount or reasonableness of costs, identification of exclusive use facilities, extent of amortization of past costs, and the

reasonableness of withholding consent, either Party may elect to submit such dispute to nonbinding arbitration. If one Party so elects, such Party shall notify the other Party in writing and both Parties shall participate pursuant to the following:

(a) If the Parties cannot agree on an arbiter within 30 days of such notification, the notifying Party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the Parties' written positions. The Party electing the arbitration shall first state its position in a letter to the arbiter. The second Party shall then state its position in a letter to the arbiter. The first Party may then submit a response to the Second Party's position and the second Party may thereafter submit a reply to the first Party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the Parties otherwise mutually agree. The Parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other Party.

(d) The arbiter shall provide the Parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The Parties shall equally share the fee and other costs of the arbiter.

In the event neither Party submits the dispute to nonbinding arbitration or if either Party elects not to accept the finding of the arbiter, the Parties may elect other approaches, including litigation, to resolve the dispute.

18. Rules of Law.

(a) The Parties agree that each fully participated in the drafting of each provision of this Agreement. The rule of law interpreting ambiguities against the drafting Party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Agreement or any of its provisions.

(b) The construction and interpretation of this Agreement shall be governed solely by Federal law.

(c) This Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither Party shall be under the control of or shall be the agent of or have a right or power to bind the other Party without the other Party's express written consent, except as provided in this Agreement.

19. Delay of Performance. The time for each act specified in this Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the Party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

20. Regulatory Jurisdiction. The provisions of this Agreement are subject to such regulatory agencies having

jurisdiction thereof. Nothing contained herein shall be construed as affecting in any way the right of PacifiCorp to make application unilaterally to the Federal Energy Regulatory Commission for a change in rates, charges, classification, or service, or any rule or regulation, or contract relating thereto, under Section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.

21. Severability and Breach.

(a) It is the intention of the Parties that the provisions of this Agreement be severable in the event that any of such provisions, or portions thereof, are held to be illegal, invalid or unenforceable by a court of competent jurisdiction; provided that if section 10 herein, or any portion thereof, is found to be illegal, invalid or unenforceable by a court of competent jurisdiction, Bonneville shall have firm transmission rights to 50 percent of the total Rated Transfer Capability of any parallel interconnections other than the 100 megawatt Cottonwood Interconnection between PacifiCorp and Pacific Gas & Electric or other utilities adjoining PacifiCorp's territory in southern Oregon and northern California. In any legal proceeding, Bonneville and PacifiCorp shall act in good faith to defend the enforceability of all provisions of this Agreement.

(b) The Parties agree that breach of this Agreement, or any of its provisions, will cause irreparable harm and that the appropriate remedy is injunctive relief.

22. Definitions.

(a) AC Intertie. For the purposes of this Agreement, the AC Intertie means Bonneville's rights in the alternating current ("AC") transmission facilities for transferring power and energy between Oregon and California as follows: two 500 kV lines extending from John Day Substation to Malin Substation and to the California-Oregon Border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Dixonville and Dixonville-Meridian 500 kV transmission lines; portions of the Alvey, Dixonville, Meridian and Captain Jack Substations; the 500 kV transmission line extending from Captain Jack Substation to the California-Oregon Border; and any modifications, improvements, or additions to such facilities.

(b) Alvey-Meridian Line. The 500 kV transmission line facilities and substations constructed by PacifiCorp that extend from the interconnection with Bonneville's system at Alvey Substation to PacifiCorp's Meridian Substation.

(c) Buckley-Alvey Loop. The 500 kV transmission lines, facilities, and substations from Buckley Substation south to Summer Lake Substation, continuing south to Malin Substation,

west to Meridian Substation, including the Captain Jack Substation, and the Alvey-Meridian Line.

(d) Captain Jack Substation. The substation where COTP interconnects with the AC Intertie in the Pacific Northwest.

(e) California Intertie. The two existing 500 kV AC lines extending northward from within California at Round Mountain Substation and terminating at Malin Substation.

(f) COTP. The 500 kV California-Oregon Transmission Project, which operates in parallel with the California Intertie and terminates at the California-Oregon Border.

(g) DC Intertie. For the purposes of this Agreement, the DC Intertie means Bonneville's rights in the existing 1,000 kV direct current ("DC") transmission line, and associated substation facilities, extending from the Bonneville's Big Eddy Substation to the Nevada-Oregon Border.

(h) Federal Transmission System. The transmission facilities owned by Bonneville.

(i) Future Pacific Northwest AC Intertie Capacity Ownership Agreements. Agreements entered into by Bonneville and regional utilities providing for those utilities' ownership of AC Intertie capacity available as a result of increasing the Rated Transfer Capability of the AC Intertie to 4800 megawatts.

(j) Incremental Capacity. For the purpose of this Agreement, Incremental Capacity means capacity realized through the construction of the Alvey-Meridian Line in excess of the capacity on the previously existing 230 kV Alvey-Meridian line

that was removed as a result of construction of the Alvey-Meridian Line.

(k) IS-A Rate. The Nonfirm Transmission Rate specified in Section II.A. of Bonneville's Southern Intertie Transmission Schedule IS-93, or its successor.

(l) Joint Intertie Scheduling Office. The group of schedulers presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, appointed by Bonneville, Portland General Electric Company and PacifiCorp and designated to coordinate the schedule of energy over the AC Intertie and the DC Intertie.

(m) Load Area. The geographic area encompassing portions of southern Oregon and northern California which is generally south of Eugene, Oregon and Bonneville's Summer Lake Substation and west of Burns, Oregon. Such geographic area shall be limited to:

(1) That area in which PacifiCorp is authorized to provide retail electric service, now and in the future; and

(2) That area in which PacifiCorp provides wholesale electric service at the date of execution of this Agreement; provided that such areas are normally within PacifiCorp's load control area, connected to PacifiCorp's transmission system, and served by the transmission lines in Exhibit C.

Revisions to the Load Area shall be by mutual agreement of the Parties, and such agreement shall not be unreasonably withheld.

(n) Load Carrying Capability. The capability of PacifiCorp's transmission system, as specified in Exhibit C, serving the Load Area and parallel paths as limited by section 10 herein to provide firm transmission service in accordance with Prudent Utility Practice.

(o) Northbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a northerly direction from the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Agreement.

(p) Off-Peak Hours. The first six and last two hours of each day Monday through Saturday and all day Sunday or other hours as mutually agreed to.

(q) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, operational limitations imposed by California utilities, line or equipment outages, stability limits or loop flow.

(r) PacifiCorp's Load. PacifiCorp's net firm load obligations within the Load Area excluding Bonneville's Surprise Valley Electric Cooperative Load transferred by PacifiCorp pursuant to the General Transfer Agreement, Contract No. DE-MS79-82BP90049.

(s) Plan-of-Service. The project plans that Bonneville develops to realize an increase of the AC Intertie Rated Transfer Capability up to approximately 4800 megawatts, which

shall include but are not necessarily limited to plans, schedules, costs, and facility and equipment requirements.

(t) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry prior thereto or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(u) Rated Transfer Capability. The ability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(v) Southbound Scheduling Rights. PacifiCorp's right to schedule power and energy through the Malin Substation and the Captain Jack Substation in a southerly direction to the 500 kV lines which extend to California and interconnect with the California Intertie and the COTP as provided in this Agreement.

Amendatory Agreement No. 2 to
Contract No. DE-MS79-86BP92299
03/09/93

AMENDATORY AGREEMENT NO. 2

TO THE INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFICORP

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This AMENDATORY AGREEMENT NO. 2 to the Intertie Agreement, Contract No. DE-MS79-86BP92299, executed March 16, 1993, by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PACIFICORP with its principal office in Portland, Oregon (hereinafter collectively referred to as "Parties" and individually as "Party").

W I T N E S S E T H :

WHEREAS the Parties hereto desire to make progress payments towards the design and construction of those facilities identified in Exhibit C to the Intertie Agreement, as amended; and

WHEREAS the Parties have entered into an Interim Payment Agreement, Contract No. DE-MS79-92BP93772 (Interim Payment Agreement), as amended, which provides for partial payment by Bonneville to PacifiCorp in the net amount of $10,000,000 for each Party's costs through May 31, 1992, related to the Alvey-Meridian Line and the AC Intertie (such payment represents a $16,000,000 payment to PacifiCorp and a $6,000,000 payment to Bonneville); and

WHEREAS the Parties have entered into a Cooperative Communication Agreement, Contract No. DE-MS79-92BP93740 (Communications Agreement), which

provides for, among other things, construction of microwave communication facilities needed for the AC Intertie (Intertie Communication Facilities); and

WHEREAS the Parties have entered into a Remedial Action Scheme Agreement, Contract No. DE-MS79-92BP93039, which provides for, among other things, cost-sharing and payment by the Parties for the remedial action scheme equipment needed to support the rated transfer capability of the AC Intertie; and

WHEREAS the Parties have entered into the Sycan Interconnection Agreement, Contract No. DE-MS79-92BP93644 (Sycan Interconnection Agreement), which provides for, among other things, the installation and connection of series capacitors and related equipment (Sycan Addition) to PacifiCorp's Summer Lake-Malin 500 kV transmission line at the Sycan Compensation Station and Summer Lake and Malin Substations; and

NOW, THEREFORE, to establish the Parties' payment obligations throughout the construction phase of the Alvey-Meridian Line; the Alvey, Dixonville, Meridian, and Captain Jack 500 kV Substations; the Sycan Addition; and the Parties' Intertie Communication Facilities; and for continued obligations related to the AC Intertie, the Parties agree to the following:

1. Term of Amendment. This Amendatory Agreement No. 2 shall be effective on the date of execution (Amendment Effective Date) and shall remain in effect concurrently with the Intertie Agreement. All liabilities incurred hereunder shall be preserved until satisfied. Section 1 of the Intertie Agreement is hereby amended to include "Prior to the termination date of this Agreement, and no later than December 31, 2009, the Parties will commence negotiations for a follow-on agreement concerning services associated with the AC Intertie unless this Agreement is extended past 2016 then the Parties will commence negotiation of a follow-on agreement 7 years prior to termination."

2. Termination of Prior Agreement. The Interim Payment Agreement is hereby terminated upon the Amendment Effective Date. All obligations and liabilities incurred thereunder have been satisfied.

3. Definitions.

(a) Section 19(o) of the Intertie Agreement is hereby amended to read:

"(o) Captain Jack Substation. The Substation where the COTP interconnects with the AC Intertie in the Pacific Northwest and is sometimes referred to as the Southern Oregon Substation."

(b) Section 19 of the Intertie Agreement is hereby amended to add the following definitions:

"(p) Actual Costs are Bonneville and PacifiCorp Direct Costs, Indirect Costs, Overhead Costs, AFUDC, Interest and Credits as defined herein which are recorded monthly to construction work in progress (CWIP), retirement work in progress, removal work in progress, or electric plant in service according to generally accepted accounting principles and Prudent Utility Practice allocable to the Alvey-Meridian Line and other related facilities identified in Exhibit C herein. Costs related to construction that would not be capitalized, such as relocation, switching, and conductor transfer shall also be included in Actual Costs. The sharing of AFUDC on CWIP and Interest on electric plant in service is dependent on the timing of payments from the other Party relative to when costs are incurred. Bonneville's normal allocation of Bonneville Overheads and Bonneville Indirect Costs shall be included in the Actual Costs. PacifiCorp's normal allocation of PacifiCorp Overheads shall be included in the Actual Costs.

"(q) Advances are the monthly amounts of projected cash flow estimates for the Cost Shared Facilities expected to be incurred as Actual Costs in a given month as specified in Exhibits G and H.

"(r) Allowance for Funds Used During Construction (AFUDC) shall be as defined in the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts found in 18 CFR, Part 101, Electric Plant Instructions 3.A [17]. AFUDC shall be an Actual Cost until the Party constructing the Cost Shared Facilities is funded by the other Party. AFUDC shall be included in CWIP.

"(s) Bonneville Direct Costs are costs which are readily identifiable or obviously traceable to a specific program, project, or other cost objective and will not be included in Bonneville's Overhead or Indirect Costs.

"(t) Bonneville Indirect Costs are any costs incurred for common objectives which cannot be directly charged to any single point of cost application. Indirect costs are often allocated to various categories of work in proportion to the benefit to each category and will not be included in Bonneville's Direct or Overhead Costs.

"(u) Bonneville Overhead Costs. Bonneville's Overhead Costs are subject to change as Bonneville's methodology for computing Overhead Costs may change and shall be reflected in the Actual Costs. Bonneville's Overhead Costs include the following and will not be included in Bonneville's Direct or Indirect Costs:

"(1) Costs that are distributed each month to benefiting programs using an annual direction of effort basis which may include automated data processing, materials and procurement, tools and work equipment, fixed wing aircraft, helicopter, General Services Administration (GSA) rent and building management, general and administrative, laboratory, and Electric Power Research Institute;

"(2) Costs that are charged to benefiting projects and programs based upon a fixed rate for services performed which include vehicle maintenance, general shops, and equipment use;

"(3) Costs that are loaded to labor charged to specific projects or programs which include personnel benefits and leave accrual; and

"(4) Costs that benefit all construction projects and are charged to all projects as construction overhead.

"(v) Cost Shared Facilities are those facilities identified in the cost share percentage column of Exhibit C herein. Such facilities shall include but are not limited to costs for land, environmental impact studies, preconstruction materials, and construction which PacifiCorp and Bonneville agree to pay through an exchange of payments in accordance with the cost share percentages as provided in Exhibit C.

"(w) Credits are the applicable portion of any income, rebate, allowance, or other receivable relating to any Cost Shared Facilities received by either Party. This includes, but is not limited to, materials, surplus property, scrap, timber revenues and future sales of Jointly-Owned and cost-shared land (Fee-Owned and Easement Rights). Proceeds from Credits shall be paid to the other Party either as a billing credit or by cash refund based on the original Cost Shared Facility proration between Bonneville and PacifiCorp.

"(x) Hazardous Substances mean any hazardous, toxic, or dangerous substance, waste, or material that is now or becomes regulated under any federal, state or local statute, ordinance, rule, regulation or other law now or hereafter in effect pertaining to environmental protection, contamination, or cleanup, including without limitation, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), 42 U.S.C.

9601 et seq., the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq., the Federal Water Pollution Control Act (CWA), 33 U.S.C. 1251 et seq., the Clean Air Act (CAA), 42 U.S.C. 7401 et seq., the Toxic Substances Control Act (TSCA), 15 U.S.C. 2601 et seq. and all comparable programs under Oregon Law.

"(y) Historic Contamination means all contamination through seepage, spill, disposal, or release by any other method, of a Hazardous Substance at or from any facility which occurred prior to the Amendment Effective Date.

"(z) Interest based on AFUDC rates and applicable to electric plant in service, shall be applied to Cost Shared Facilities placed in service before cost reimbursement has occurred.

"(aa) Jointly-Owned refers to those facilities identified in Exhibit C which are not solely owned by either Party.

"(bb) PacifiCorp Direct Costs are costs which are readily identifiable or obviously traceable to a specific program, project, or other cost objective and will not be included in PacifiCorp's Overhead Costs.

"(cc) PacifiCorp Overhead Costs are costs incurred which cannot be directly charged to any single point of application. PacifiCorp Overhead Costs are assigned to various categories in proportion to the benefit of each category. PacifiCorp overhead transactions are made by either allocations or by clearing. PacifiCorp's Overhead Costs are subject to change as PacifiCorp's methodology for computing Overhead Costs may change and shall be reflected in Actual Costs. PacifiCorp Overhead Costs include the following components and will not be included in PacifiCorp's Direct Costs:

"(1) Labor Loading. These costs are directly associated personnel costs and include payroll taxes, leave, and benefits.

"(2) Material Overheads (for stores issues and for direct purchases) includes the costs of purchase, storage, handling and distribution of materials and supplies.

"(3) Tool Overheads represent the costs incurred to the purchase, use, and maintenance of small tools for force account work.

"(4) Transportation Overheads represent the costs incurred to purchase, lease, rent, operate, and maintain the fleet of PacifiCorp vehicles.

"(5) Construction (General) Overheads are all other construction costs incurred as a corporation, but which are not assignable to a specific project. Construction Overheads are applied to PacifiCorp's Direct Costs plus PacifiCorp's Overhead Costs described above in Sections cc(1) through cc(4).

"(dd) Prior Costs. Actual Costs for Cost Shared Facilities incurred by the Parties through December 31, 1991, which are identified in section 7(b) to this Amendment.

"(ee) Project Diagram. Exhibit F to this Amendment describes the plan-of-service for the Eugene-Medford (Alvey-Meridian) project."

4. Revision of Exhibits. Section 2 of the Intertie Agreement is hereby deleted in its entirety and replaced with the following:

"2. Exhibits. Exhibits A through K are hereby incorporated as part of the Intertie Agreement as amended. Revisions to the Exhibits, except for Exhibit K shall be by mutual consent."

The monthly Operation and Maintenance (O&M) charge in Exhibit K may be revised unilaterally by Bonneville once every year to be effective on July 1, but not until after January 1, 1994.

5. Accounting and Record Keeping.

(a) Record Keeping. Each Party shall keep up-to-date books and records of financial transactions, and other arrangements in carrying out the terms of this Amendatory Agreement No. 2. Such books and records shall be kept in accordance with the system of accounts prescribed for electric utilities by FERC and shall be available for inspection on a regular basis to the other Party. Each Party shall have access to such records of the other Party as required for audit, for state and local tax preparation purposes, for regulatory purposes, and as necessary for engineering, design, and project management review.

(b) Continuing Property Records. Each Party shall maintain the complete cost records and investment reports on facilities they constructed in accordance with the Project Diagram, as well as investment records which delineate the ownership percentage in facilities constructed by the other Party.

For example, Bonneville will record 100 percent of the facilities constructed by Bonneville with an offsetting credit for PacifiCorp's percentage of ownership of those facilities and record Bonneville's ownership percentage of facilities constructed by PacifiCorp.

In conjunction with the final accounting and true-up of project costs, Bonneville and PacifiCorp shall exchange investment records and appropriate support documentation normally required for FERC account investment analysis. This may include, but is not limited to, structure/hardware lists, plan and profile drawings, and bills of materials. Bonneville and PacifiCorp shall provide periodic exchanges of information as necessary to properly identify

replacements, retirements, additions and improvements as such activities occur on the Jointly-Owned facilities.

(c) Capital Spare Parts. Capital spare parts for the Jointly-Owned facilities are subject to joint-ownership and cost-sharing if they are unique to a specific Jointly-Owned or Cost Shared Facility and if they are stored at or near the Cost Shared Facilities. Spare parts that are charged to inventory shall not be cost-shared until the spare part is placed in service at a Jointly-Owned facility.

6. Capital Budgets. Four years prior to the year costs are expected to be incurred, each Party shall provide to the other Party a forecast of capital budget expenditures related to the planned construction and operation activities of the Cost Shared Facilities except for the excluded facilities identified by a footnote in Exhibit C. This forecast shall be provided to the other Party on or before July 1 of each year and shall include updates of any estimated costs for the next 3 years. The Parties shall exchange and review any necessary data as needed to determine the necessity and adequacy of the proposed construction and operation activities. This notification requirement shall not apply to emergency replacement of equipment.

7. Payment Provisions.

(a) Payments made under this Amendment shall be made in accordance with provisions in this section 7 and shall be made for the following periods:

(1) Actual Costs for Cost Shared Facilities incurred for Prior Costs;

(2) Advances and Actual Costs for the Cost Shared Facilities incurred for the period from January 1, 1992, through the last month listed in the cash flow exhibits, Exhibits G and H by monthly invoices in accordance with Section 7(c) Progress Payments;

(3) Payment or refund for the final accounting of Actual Costs in accordance with Section 7(d) Final Accounting of Costs;

(4) Payment for future capital replacements in accordance with Section 7(e) and tables to Exhibit J; and,

(5) Payment for Operation and Maintenance shall be in accordance with Exhibit K.

Bonneville and PacifiCorp shall specify the financial institution and account number in a written notice to each other at the invoicing address and provide updates as necessary for the transfer of funds. Each invoice shall include a reference to Contract No. DE-MS79-86BP92299 and an invoice number.

(b) Prior Costs Payments. Bonneville shall pay PacifiCorp by check or electronic transfer of funds within 30 days after the date of an itemized invoice for PacifiCorp's Prior Costs, $10,047,832.97 as agreed to by the Parties pursuant to the audit dated February 4, 1993. The date of such invoice shall be no earlier than the mailing date of such invoice. Such amount represents payment to PacifiCorp of Prior Costs through December 31, 1991, except for land and related land costs which may be subject to adjustment after Bonneville's receipt and review of all PacifiCorp's legal conveyance documents in accordance with Sections 8 and 14. Adjustments of Prior Costs as a result of PacifiCorp's final analysis of accounts performed for the final accounting of costs shall also be made upon mutual agreement of the Parties.

PacifiCorp shall pay Bonneville by check or electronic transfer of funds within 30 days after the date of an itemized invoice for Bonneville's Prior Costs, $4,920,877.92, as agreed to by the Parties pursuant to the audit dated December 31, 1992. The date of such invoice shall be no earlier than the mailing date of such invoice. Such amount represents payment to Bonneville of

Prior Costs through December 31, 1991, except for land and related land costs which may be subject to adjustment after PacifiCorp's receipt and review of all Bonneville's legal conveyance documents in accordance with Sections 8 and 14. Adjustments of Prior Costs as a result of Bonneville's final analysis of accounts performed for the final accounting of costs shall also be made upon mutual agreement of the Parties.

(c) Progress Payments. Each Party shall make monthly payments to the other Party for the Cost Shared Facilities incurred after January 1, 1992, in accordance with Sections 7(c)(1) and 7(c)(2) below. The initial invoice shall also include amounts due for all past months from January 1, 1992, through the Amendment Effective Date with a credit for the amount previously paid under the Interim Payment Agreement.

(1) Payment by PacifiCorp. Each month Bonneville shall submit an itemized invoice to PacifiCorp (Jerry Walker, 800 PSB, 920 SW. Sixth Avenue, Portland, Oregon 97204) for the next month's Advance, in accordance with Exhibit G, and any adjustments for the previously invoiced Advance amounts when Actual Costs for such month(s) are known. The date of such invoice shall be no earlier than the mailing date of such invoice. The Actual Costs adjustment shall identify the Cost Shared Facilities with an itemization of cost elements by Bonneville work functions (i.e., materials, design, construction, etc.)

PacifiCorp shall pay Bonneville by check or electronic transfer of funds within 30 days after the date of the invoice. Should the 30th day be a Saturday, Sunday, or holiday, as observed by PacifiCorp, then the due date shall be the next following business day.

A credit balance on an invoice of $100,000 or less shall be carried forward to the next month's invoice. A credit balance on an invoice of

more than $100,000 shall be refunded to PacifiCorp by check or electronic transfer of funds within 15 days of the date of Bonneville's credit invoice. A refund of the credit balance shall also be made, regardless of the amount, if the sum of the remaining Advances is less than the credit balance.

(2) Payment by Bonneville. Each month PacifiCorp shall submit an itemized invoice to Bonneville (Bonneville Power Administration, P.O. Box 3621 - DSAC, Portland, Oregon 97208-3621) for the next month's Advance in accordance with Exhibit H, and any adjustments for the previously invoiced Advance amounts when Actual Costs for such month(s) are known. The date of such invoice shall be no earlier than the mailing date of such invoice. The Actual Costs adjustment shall identify the Cost Shared Facilities with an itemization of cost elements (i.e., labor, materials, purchase services, miscellaneous and overheads, etc.)

Bonneville shall pay PacifiCorp by check or electronic transfer of funds within 30 days after the date of the invoice. Should the 30th day be a Saturday, Sunday, or holiday as observed by Bonneville, then the due date shall be the next following business day.

A credit balance on an invoice of $100,000 or less shall be carried forward to the next month's invoice. A credit balance on an invoice of more than $100,000 shall be refunded to Bonneville by electronic transfer of funds within 15 days of the date of PacifiCorp's credit invoice. A refund of the credit balance shall also be made, regardless of the amount, if the sum of the remaining Advances is less than the credit balance.

(d) Final Accounting of Costs. Within 3 years after the date of commercial operation of all the Jointly-Owned and Cost Shared Facilities,

Bonneville and PacifiCorp shall each prepare a final accounting of all Actual Costs incurred for the Cost Shared Facilities identified in Exhibit C.

Each Party shall prepare an itemized invoice for the total final Actual Costs with either a refund or payment due the other Party. Payments and refunds shall be made in accordance with Sections 7(c)(1) and 7(c)(2).

(e) Payment Provisions for Capital Replacements:

(1) For reimbursable Capital Replacements, either Party shall prepare, for execution by the Parties hereto, an additional table to Exhibit J each time the Parties hereto agree that facilities shall be added or replaced to those facilities identified in Exhibit C to the Intertie Agreement. Those facilities identified by footnote one in Exhibit C shall be exempt from further cost sharing on capital replacements. Each table shall specify the facilities to be installed, the work to be performed by each Party, and the estimated costs to be borne by each Party. Payments shall be made as provided in each table to Exhibit J for the work to be performed in amounts and at times requested by the Party due reimbursement.

(2) Upon execution by the Parties hereto, new tables to Exhibit J shall be attached to and deemed to be a part of this Amendment to the Intertie Agreement and shall be effective on the date specified therein.

(f) Operation and Maintenance Charges. Effective on December 18, 1992, and pursuant to Exhibit K, PacifiCorp shall pay Bonneville for 50 percent of the operation and maintenance of the three Alvey 500 kV power circuit breaker terminals. Such operation and maintenance charge shall be included in PacifiCorp's monthly Wholesale Power Bill and shall remain in effect until such time the Alvey 500 kV facilities are available for commercial operation as part of the AC Intertie. Effective on December 18, 1992, PacifiCorp shall

pay Bonneville 35 percent of the operation and maintenance of the series capacitors at the Sycan Compensation Station (Sycan) pursuant to Exhibit K. Such operation and maintenance charge shall be included in PacifiCorp's monthly Wholesale Power Bill and shall remain in effect until such time as the Alvey-Meridian transmission line is available for commercial operation as part of the AC Intertie. However, the payments for such operation and maintenance charges shall be provided for in the follow-on Operations and Maintenance Agreement from the date of commercial operation as part of the AC Intertie.

(g) Disputed Billing. In the event of a disputed billing, full payment shall be made with written notification of the disputed amount. If it is determined that an adjustment is required, the adjustment shall be made on the next invoice allowing reasonable notice and time to make the adjustment. Refunds of the disputed amount shall include interest at the same interest rate specified in Section 7(h) below.

(h) Late Payment by Bonneville or PacifiCorp. Invoices not paid in full on or before the close of business on the due date shall be subject to an interest charge on the amount due from the due date to the date paid consistent with the Prompt Payment Act Renegotiation Board's Interest Rate published in the Federal Register.

8. Audit. Each Party, at its expense, shall have the right to review and audit any cost on the other Party's books, records, and documents that directly pertain to the billings, investments, and costs of the Cost Shared Facilities. Any audit(s) shall be undertaken by either Party's representative(s) upon reasonable notice to the other Party and at reasonable times and in conformance with generally accepted auditing standards. The foregoing shall not be construed to permit either Party to conduct a general audit of the other Party's records beyond those needed to perform an audit of the Cost Shared

Facilities. The Party being audited agrees to cooperate fully with any such audit(s). The right to audit a cost shall extend for a period of 3 years following the last day of the fiscal year in which such cost was incurred or the final accounting of costs under this Amendment. If either Party does not audit the costs of the other Party for fiscal years 1992, 1993, or 1994, prior to the completion of the final accounting of costs, the right to audit those costs shall extend for a period of 3 years after the date of completion of the final accounting of costs. The Parties agree to retain all records and documentation prepared in the normal course of business for the entire length of this audit period and in accordance with generally accepted accounting principles.

The Party being audited shall be notified promptly in writing of any exception taken as a result of an audit after completion of the audit. The Party being audited shall have 30 days to review the notice of exception. If the Parties agree upon any exception(s) found as a result of the audit, the owing Party shall directly refund the amount of such exception(s) within 30 days of such agreement to the other Party. In the event of late payment, the Late Payment Provisions of Section 7(h) shall apply to amounts not paid in full by the due date.

Prior to the Amendment Effective Date, the Parties performed audits of each Party's Prior Costs. Such costs shall not be subject to additional audits, except for the audit of supporting documentation required for accounting adjustments that may have originated from the Prior Cost audit. However, both Parties reserve the right to review Prior Costs billed under Section 7(b) for land and related land costs. Any Prior Cost adjustment shall be determined after a Party receives and reviews all legal conveyance documents

from the other Party. The results of the Prior Cost audits and resulting amounts due are reflected in Section 7(b).

9. Ownership of Facilities.

(a) Transfer of legal ownership pursuant to Amendatory Agreement No. 2 shall be effective at such time the facilities are energized and made available for commercial operation as part of the AC Intertie and shall remain in effect so long as any facilities of the Alvey-Meridian Line are in existence and operable and shall survive the term of the Intertie Agreement.

(b) All Jointly-Owned equipment, facilities, and capital spare parts shall be identified as such with co-ownership tags and signs. Either Party, at such Party's sole expense, shall provide the tags and signs.

10. Operation and Maintenance of Facilities.

(a) The Parties agree that Section 1(b) to Amendment No. 1 to the Intertie Agreement is hereby replaced in its entirety by the following:

"(b) Maintenance and Operation. PacifiCorp shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors; the terminal facilities at Meridian Substation for the Dixonville-Meridian Line, including the series capacitors; the Alvey-Meridian Line; PacifiCorp's relays, digital fault recorder, and SCADA remote terminal unit at Captain Jack Substation; the loop-in of PacifiCorp's Malin-Meridian 500 kV Line at Captain Jack Substation; PacifiCorp's relays installed at Summer Lake and Malin Substations; PacifiCorp's Dead-End Tower installed at Sycan as part of the Sycan Addition; and all communication facilities owned by PacifiCorp. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors; all the facilities at Captain Jack Substation other than PacifiCorp's relays,

digital fault recorder and SCADA remote terminal unit; the Sycan Addition other than PacifiCorp's Dead-End Tower; and all communication facilities owned by Bonneville. The Parties shall exchange maintenance standards with each other and shall carry out their respective maintenance responsibilities according to Prudent Utility Practices. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Exhibit C, as amended."

(b) The Parties shall use best efforts to develop and execute a new AC Intertie Operation and Maintenance Agreement for the facilities identified in Exhibit C by December 1993. During the period between the energization date of any of these facilities and the date that such facilities are available for commercial operation as part of the AC Intertie, operation and maintenance shall be provided by the Parties as identified in Section 10(a) above and Exhibit C to the Intertie Agreement, without charge to the other Party, except for those facilities identified in Section 7(f) of this Amendatory Agreement.

11. Environmental Requirements.

(a) Historic Contamination. Neither Party shall be liable for any fines, penalties and assessments, costs for investigation, response, removal and remediation, arising from Historic Contamination of facilities owned by the other Party or operated by the other Party prior to becoming Jointly-Owned facilities pursuant to this Amendment.

(b) Disclosure of Information. Bonneville shall provide PacifiCorp, within 90 days after the Amendment Effective Date, a summary of all known and suspected Hazardous Substance release, spill and disposal events at facilities described herein which occurred prior to the Amendment Effective Date. PacifiCorp may request and Bonneville shall provide, for the purpose of establishing baseline contamination data for the facilities transferred to

Jointly-Owned facilities pursuant to this Amendment, all information including records, files and documentation pertaining to all known and suspected Hazardous Substance release, spill and disposal events at such transferred facilities. Such information shall also include correspondence, requests, determinations, findings and orders made by or to Federal, state or local agencies in connection with known and suspected Hazardous Substance release, spill and disposal events.

PacifiCorp shall provide Bonneville, within 90 days after the Amendment Effective Date, a summary of all known and suspected Hazardous Substance release, spill and disposal events at PacifiCorp's facilities described herein which occurred prior to the Amendment Effective Date. Bonneville may request and PacifiCorp shall provide, for the purpose of establishing baseline contamination data for the facilities transferred to Jointly-Owned facilities pursuant to this Amendment, all information including records, files, and documentation pertaining to all known and suspected Hazardous Substance release, spill and disposal events at such transferred facilities. Such information shall also include correspondence, requests, determinations, findings and orders made by or to Federal, state or local agencies in connection with known and suspected Hazardous Substance release, spill and disposal events.

(c) Emergency Environmental Responsibility. The Party in operational control of a Jointly-Owned facility shall prepare and obtain approval required for emergency response plans for Hazardous Substance releases from all appropriate Federal, state and local agencies and shall be responsible for management and implementation of all laws and regulations pertaining to Hazardous Substances at the Jointly-Owned facility. Costs associated with

approval and implementation of such plans shall be included in the Actual Costs.

12. Capital Replacements. Cost sharing for replacement of facilities specified in Exhibit C, due to obsolescence or major failure, shall be shared by the Parties according to the original cost share percentage of such facilities and in accordance with Exhibit J and Section 7(e) except for the excluded facilities identified by footnote one in Exhibit C.

13. Decommissioning Costs. The Parties shall pay decommissioning costs of Jointly-Owned facilities in accordance with their ownership shares as specified in Exhibit C. Proceeds from the disposal of Jointly-Owned surplus property or facilities shall be equitably distributed or allocated to the Parties in accordance with their ownership shares as specified in Exhibit C. The cost-sharing of decommissioning costs shall survive the term of the Intertie Agreement.

14. Land and Improvements. Right-of-way and land costs for the Alvey-Meridian Line and for Alvey, Dixonville, Meridian, and Captain Jack Substations will be cost-shared consistent with Exhibit C and the following principles. Bonneville's land maps are attached as Exhibit I, 1 and 2. PacifiCorp's land drawings attached as Exhibit I 3 through I 9 represent the Parties intent using such generic examples.

(a) Alvey-Spencer Line. Right-of-way and/or land costs shall conform to the following:

(1) If Bonneville acquires new right-of-way (Easement Rights) on land not owned by Bonneville, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost to purchase such Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, pages 1 of 13 and 2 of 13, provide an example of such right-of-way.

(2) If PacifiCorp uses existing right-of-way (Fee-Owned Land), Bonneville will not share in the cost and will receive easement for access only for such Fee-Owned Land. This includes land owned by PacifiCorp adjacent to PacifiCorp's Spencer Switchstation (Section 22, Township 18 South, Range 3 West, W.M.).

(b) Spencer-Meridian 500 kV Line. Right-of-way and/or land costs shall conform to the following:

(1) If PacifiCorp acquires new right-of-way (Easement Rights) on land not owned by PacifiCorp, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost to purchase such Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, page 4 of 13, page 6 of 13, and page 7 of 13, provides examples of such right-of-way.

(2) If PacifiCorp acquires new land (Fee-Owned Land) for the sole purpose of providing right-of-way for the Spencer-Meridian Line, Bonneville and PacifiCorp will each pay 50 percent of the Actual Cost of acquiring such Fee-Owned Land and will each receive 50 percent ownership of the Fee-Owned Land actually utilized to provide the necessary right-of-way. This includes land that is excess to normal right-of-way requirements which was purchased to provide necessary right-of-way and has been rendered non-marketable due to the transmission line construction. Exhibit I, page 5 of 13 and page 8 of 13, provides examples of such right-of-way.

(3) If PacifiCorp acquires new land (Fee-Owned Land) to provide right-of-way for the Spencer-Meridian Line, which it intends to market or retain portions thereof for its own purposes, PacifiCorp will provide and maintain Easement Rights for the portion of such Fee-Owned Land necessary

for such right-of-way. Bonneville and PacifiCorp will each pay 50 percent of the Actual Costs to provide Easement Rights and will each receive 50 percent interest in such Easement Rights. Exhibit I, page 5 of 13, provides an example of such right-of-way.

(4) If PacifiCorp uses existing right-of-way (Easement Rights or Fee-Owned Land), Bonneville will not share in the cost and will receive easement for access only in addition to an ownership interest in the Alvey-Meridian 500 kV Transmission Line.

(5) If PacifiCorp secures any permits for right-of-way across public lands, Bonneville and PacifiCorp will each pay 50 percent of the Actual Costs associated with such permits and will each receive 50 percent interest in such permits. Exhibit I, page 7 of 13, provides an example of such right-of-way.

(6) If, in the future, PacifiCorp markets any of the Fee-Owned Land as described in Section 14(b)(2) herein for which Bonneville has paid PacifiCorp 50 percent of the Actual Costs, Bonneville will receive 50 percent of the sale proceeds, less expenses.

(c) Substations. Right-of-way and/or land costs shall conform to Exhibit C and the following:

(1) Alvey Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 10 of 13, and each Party will receive a 50 percent ownership.

(2) Dixonville Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 11 of 13, and each Party will receive a 50 percent ownership.

(3) Meridian Substation. Land will not be cost-shared jointly on the existing land as shown in Exhibit I, page 12 of 13. Bonneville will receive Easement Access only.

(4) Captain Jack Substation. Land will be cost-shared jointly on square footage of usage within the area shown on Exhibit I, page 13 of 13, and PacifiCorp will receive a 100 percent ownership of such specific area.

(d) Title Transfer. Title and easement rights will be transferred by and to the Parties by a recordable conveyance document agreeable to both Parties after energization of the Alvey-Meridian Line.

To accomplish this, each Party will provide the other a copy of each recorded conveyance instrument and all permits obtained. Each instrument will be identified by category Exhibit I, page 4 of 13 through page 9 of 13. A full set of property maps will also be provided by each Party to the other depicting ownership acquisition. Both acquisition documents and a full set of property records (Plans) will be given by each Party to the other within 30 days after execution of this Amendment.

15. Notices. Any notice required to be served in accordance with the terms of this Agreement, shall be in writing and sent by registered or certified mail, return receipt requested, to the appropriate address listed below:

Bonneville Power Administration
P.O. Box 3621 - P
Portland, OR 97228-3621

PacifiCorp
Jerry Walker, 800 PSB
920 SW. Sixth Ave.
Portland, OR 97204

16. Liability.

(a) Bonneville and PacifiCorp assert that neither Party is the agent or principal for the other or that they are partners or joint venturers; and the Parties agree that they will not represent to any other party that they act in The capacity of agent or principal for the other. Any judgments in tort obtained against either Party shall not be an Actual Cost of the Cost Shared Facilities.

IN WITNESS WHEREOF, the Parties hereto have executed this Amendatory Agreement in several counterparts.

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/type)

Title Vice President

Date March 16, 1993

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____

Name Randall W. Hardy
(Print/type)

Title Administrator

Effective Date March 16, 1993

(VSIO-PMTT-3568e)

Exhibit F, Page 1 of 2
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
Pacificorp
Effective at 2400 hrs
on the effective date

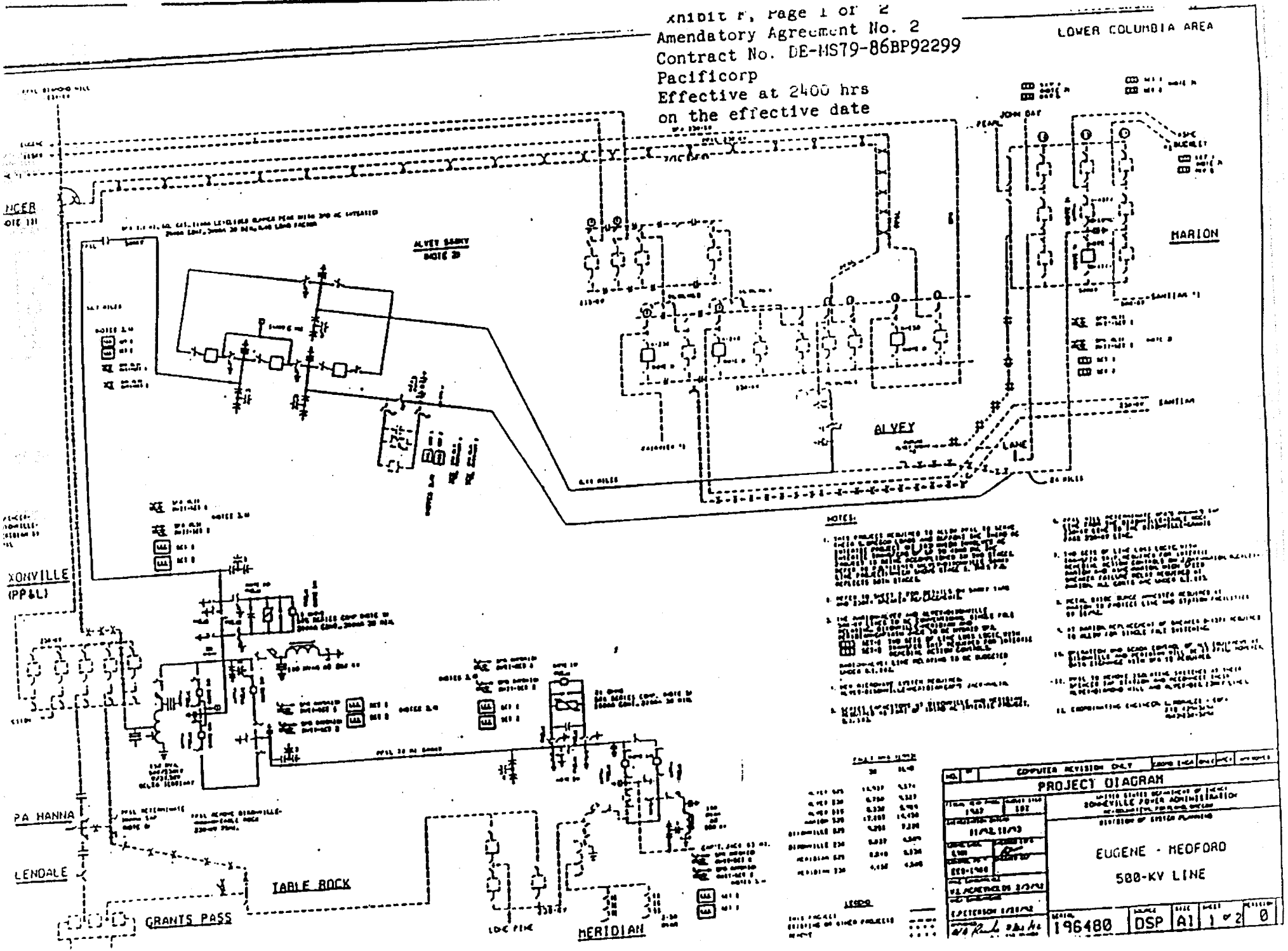
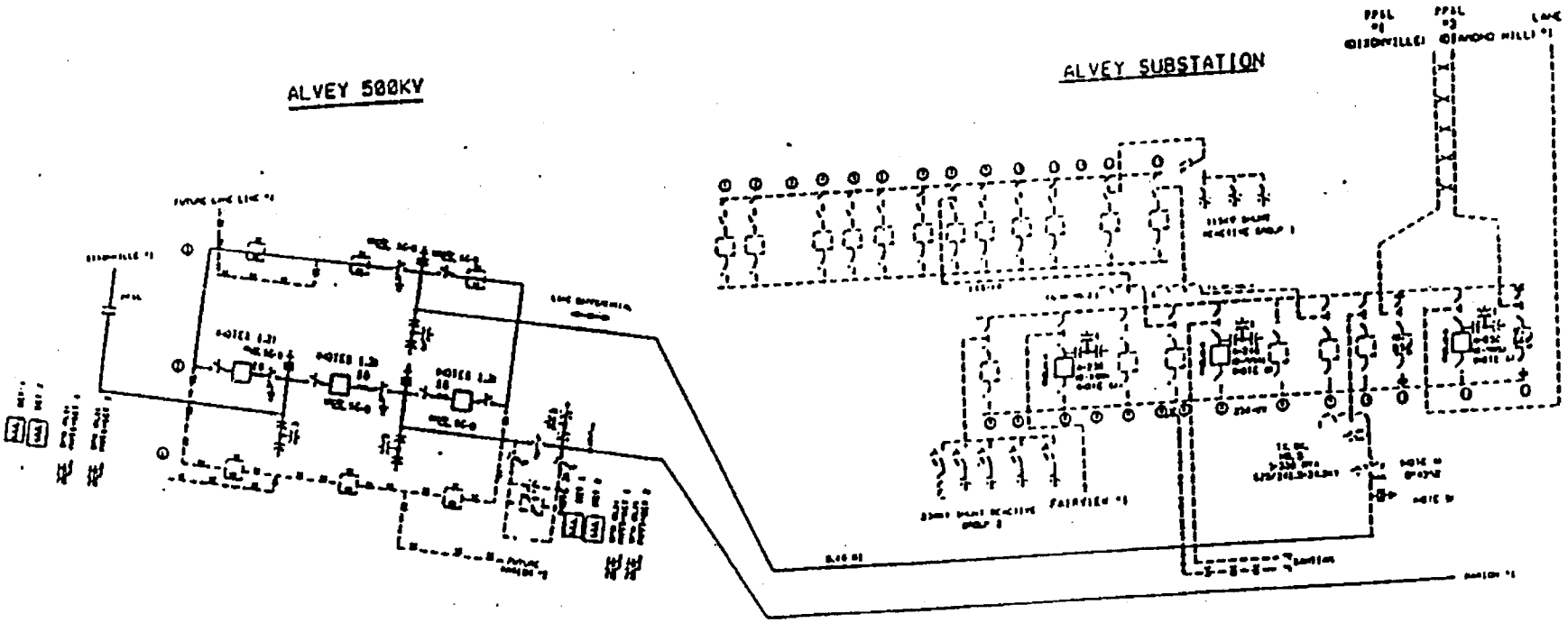


Exhibit F, Page 2 of 2
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
Pacificorp
Effective at 2400 hrs
on the effective date



FAULT MVA (1993)

	3Ø	LL-G
ALVEY 525	18927	9574
ALVEY 230	8356	9327
ALVEY 115	9336	8459

PROJECT DIAGRAM

EUGENE - MEDFORD
500-KV LINE
ALVEY SUBSTATION

196480 | DSP | A1 | 2 of 2

Bonneville Cash Flow
(Dollars in Thousands)

Year	Month	Advances
1992	January through September	$ 5,534
	October	3,047
	Less Interim Payment	(6,000)
	November	392
	December	220
1993	January	585
	February	585
	March	769
	April	750
	May	325
	June	132
	July	166
	August	166
	September	78
	October	73
	Total	$ 6,822

Source Document:
Bonneville Eugene-Medford Project Cash Flow Estimates
Prepared by J. Quinata, dated 1/25/93
Prior Costs are excluded.

(VS10-PMTT-3596e)

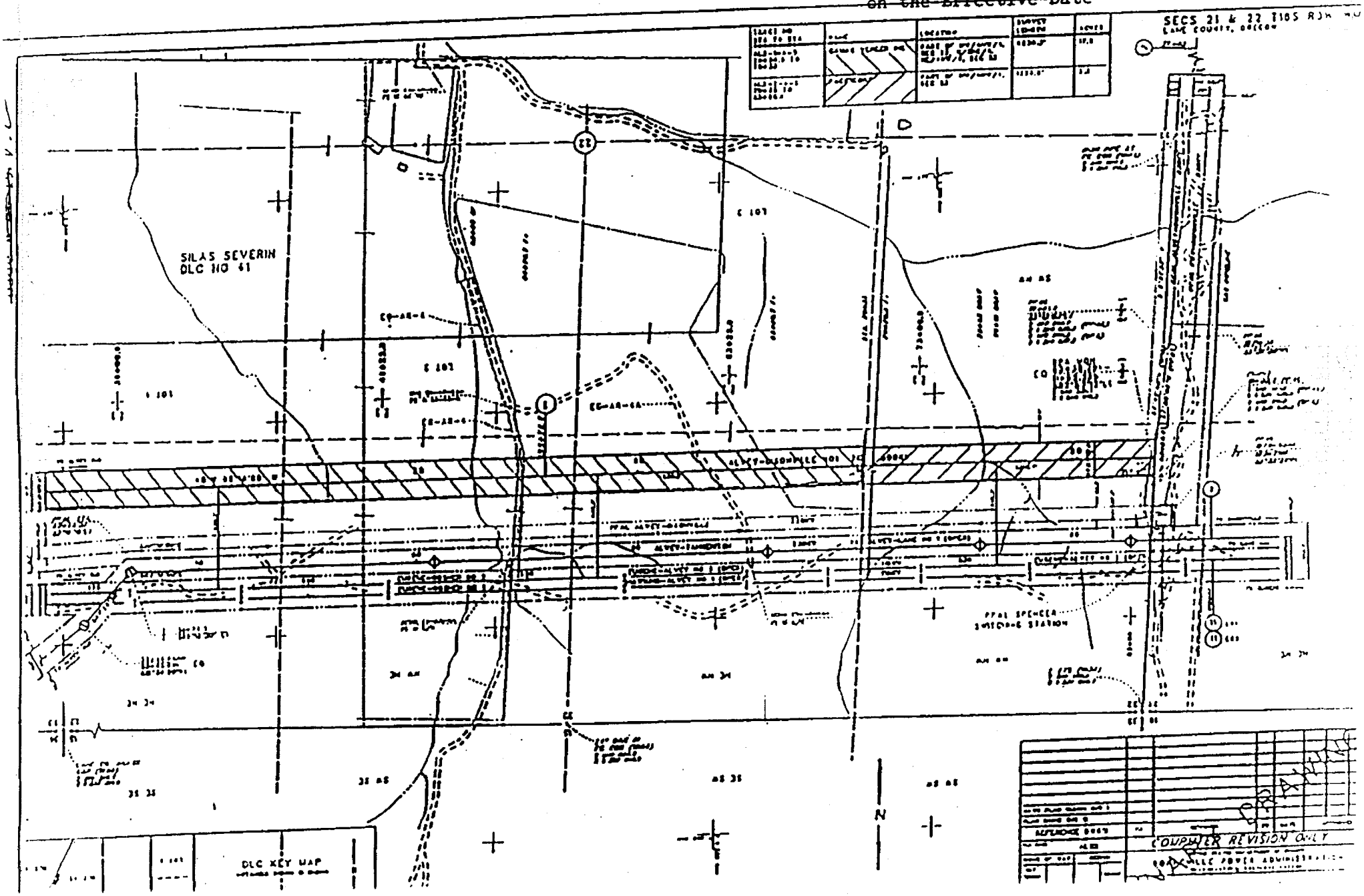
PacifiCorp Cash Flow
(Dollars in Thousands)

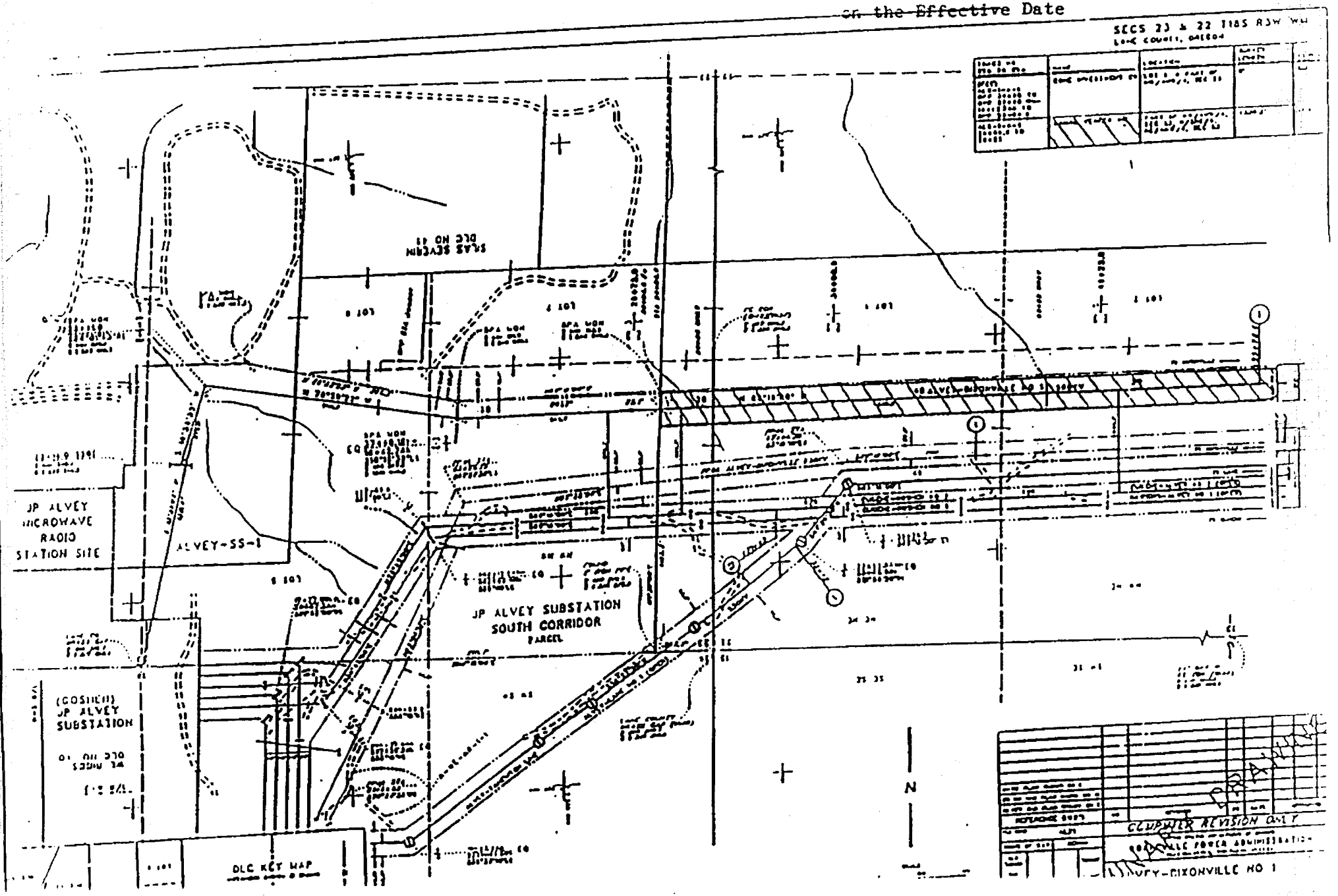
Year	Month	Advances
1992	January through September	$ 25,125
	October	3,897
	Less Interim Payment	(16,000)
	November	3,000
	December	4,500
1993	January	2,896
	February	1,995
	March	1,853
	April	1,788
	May	2,076
	June	2,103
	July	2,026
	August	1,800
	September	1,492
	October	1,579
	November	1,101
	December	234
	Total	$ 41,465

Source Document:
PacifiCorp: October 1992 Project Forecast
Southern Oregon 500 kV Project
Prepared by T. Jestrab, dated 12/31/92
Prior Costs are excluded.

(VS10-PMTT-3596e)

Exhibit I, Page 1 of 13
Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
~~on the Effective Date~~




JP ALVEY MICROWAVE RADIO STATION SITE
ALVEY-SS-1
JP ALVEY SUBSTATION SOUTH CORRIDOR PARCEL
(PROPOSED) JP ALVEY SUBSTATION
DLC KEY MAP
N
ALVEY-DIXONVILLE NO 1

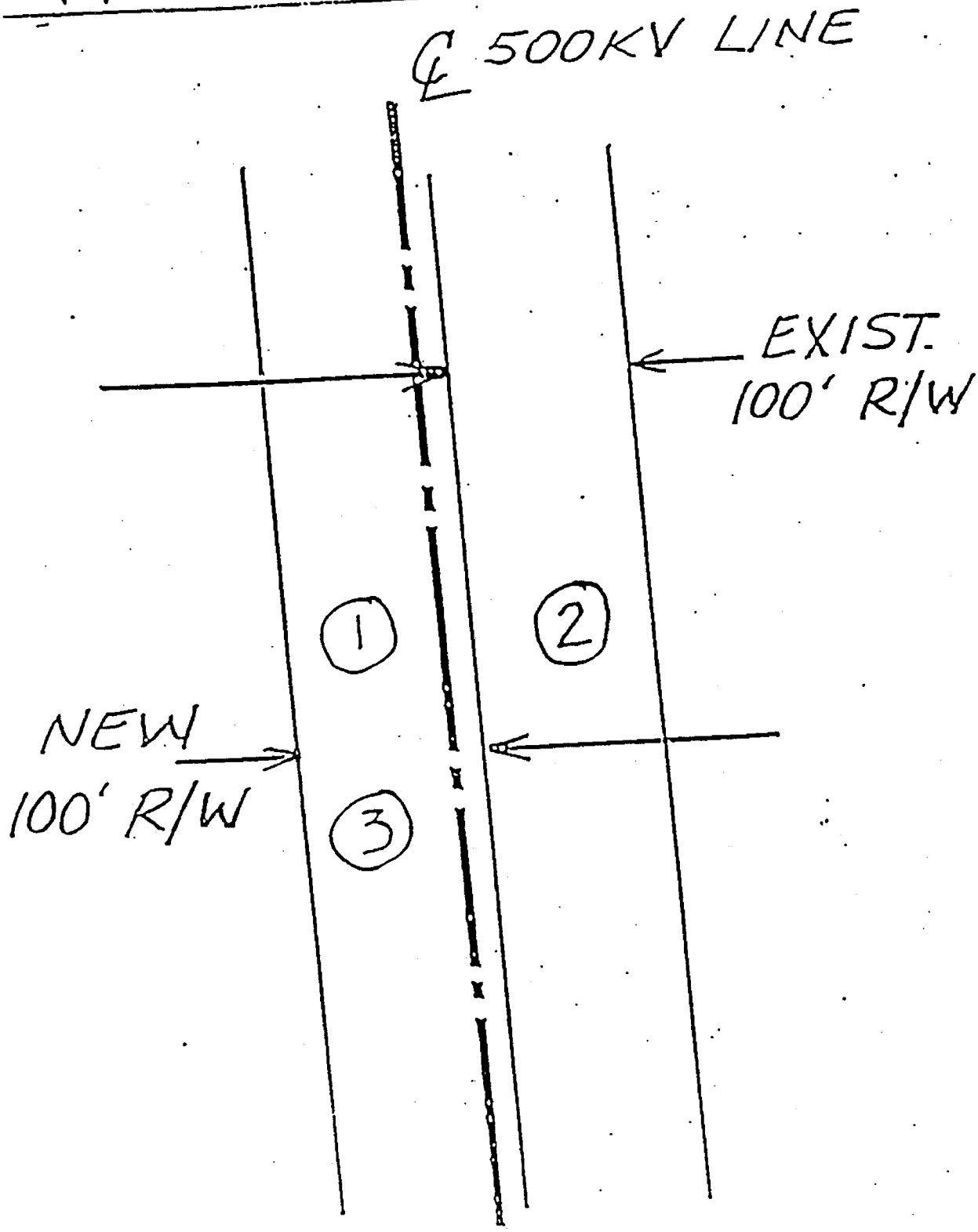
LEGEND

(1) - SHARED COST

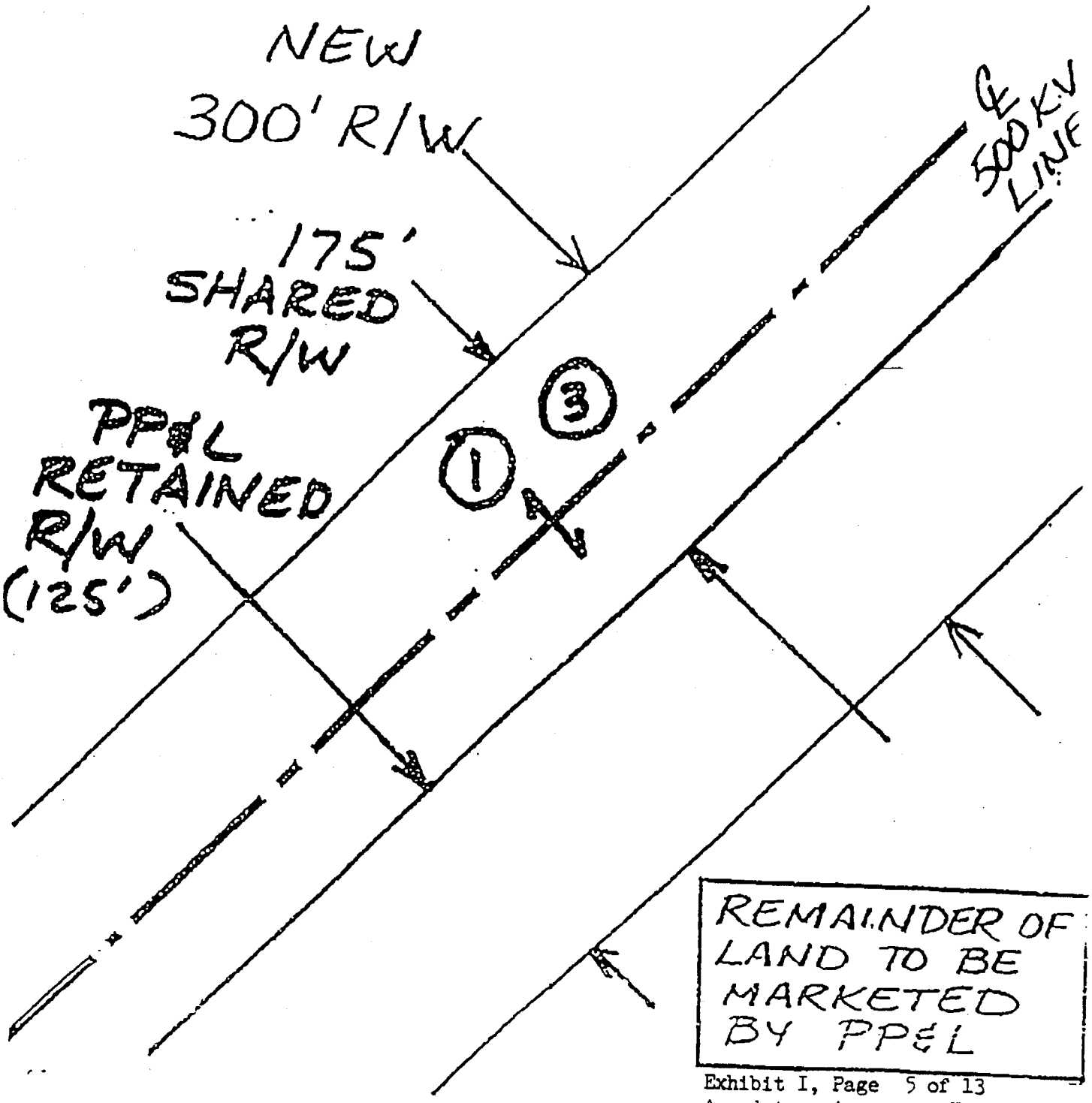
(2) - SHARED EASEMENT ACCESS ONLY

(3) - SHARED EASEMENT RIGHTS

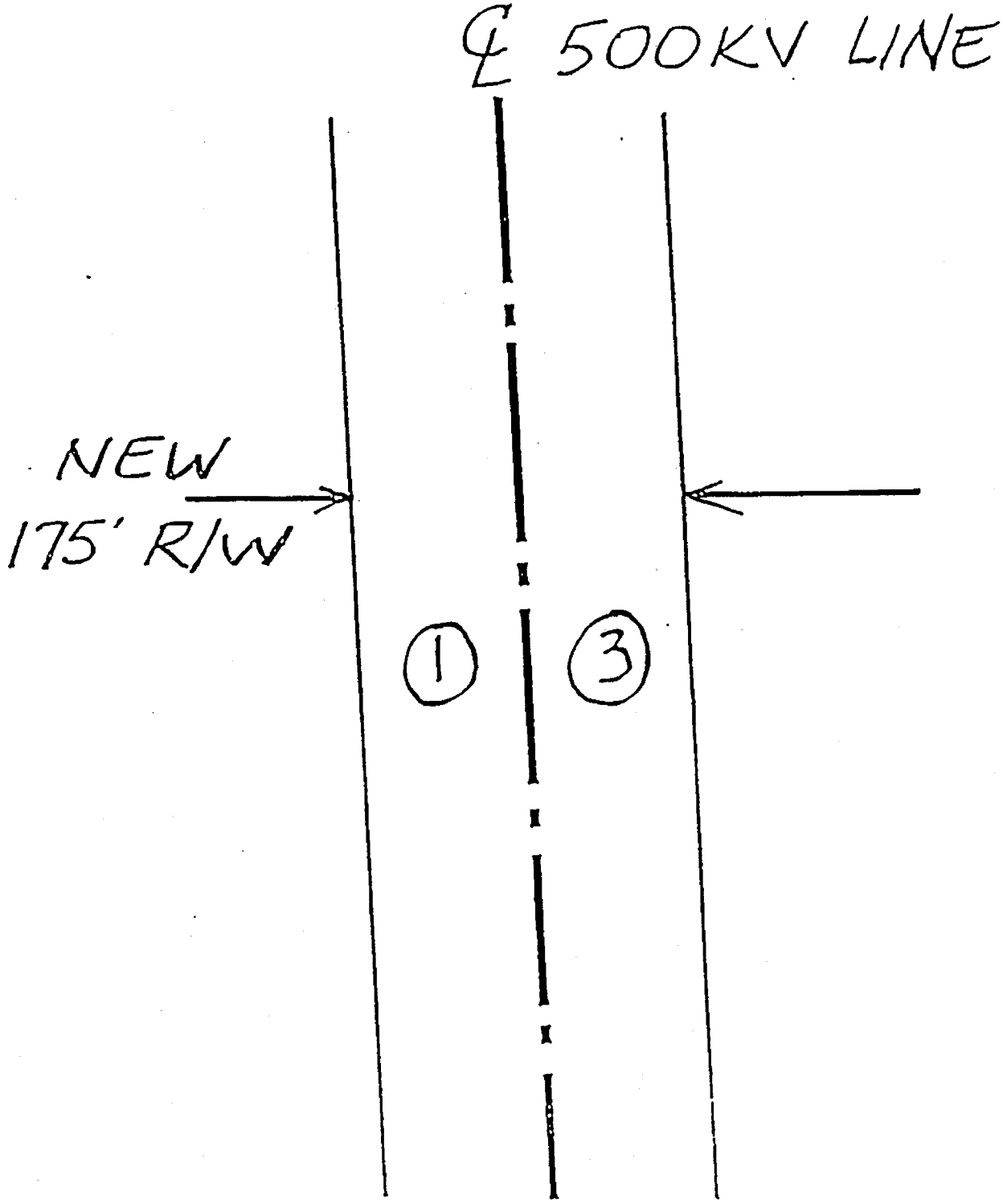
A. EXISTING R/W PRIVATE LAND - (1)



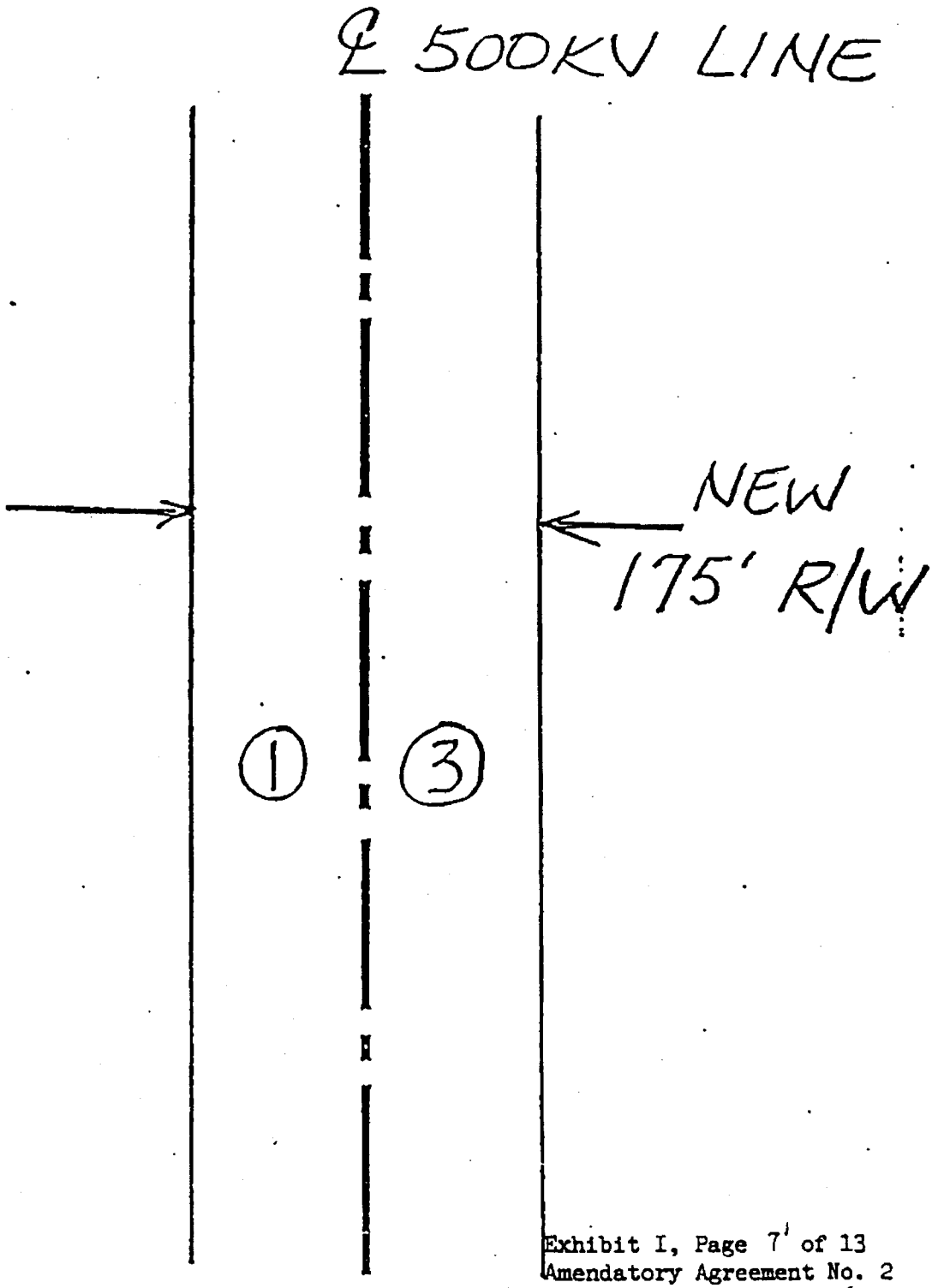
B. NEW R/W ON PP&L FEE OWNED LAND - (1



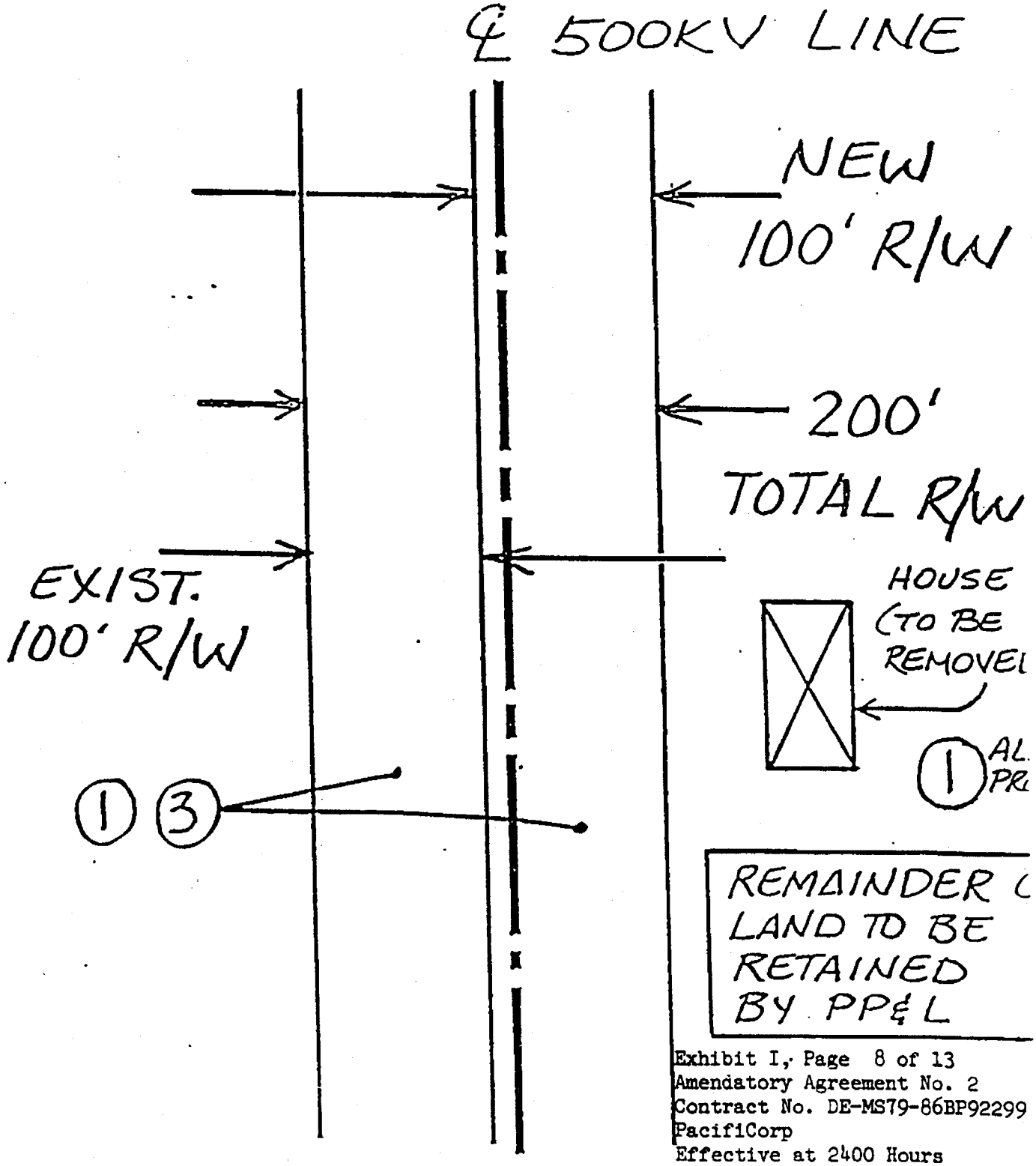
C. NEW R/W 82'
PRIVATE LAND



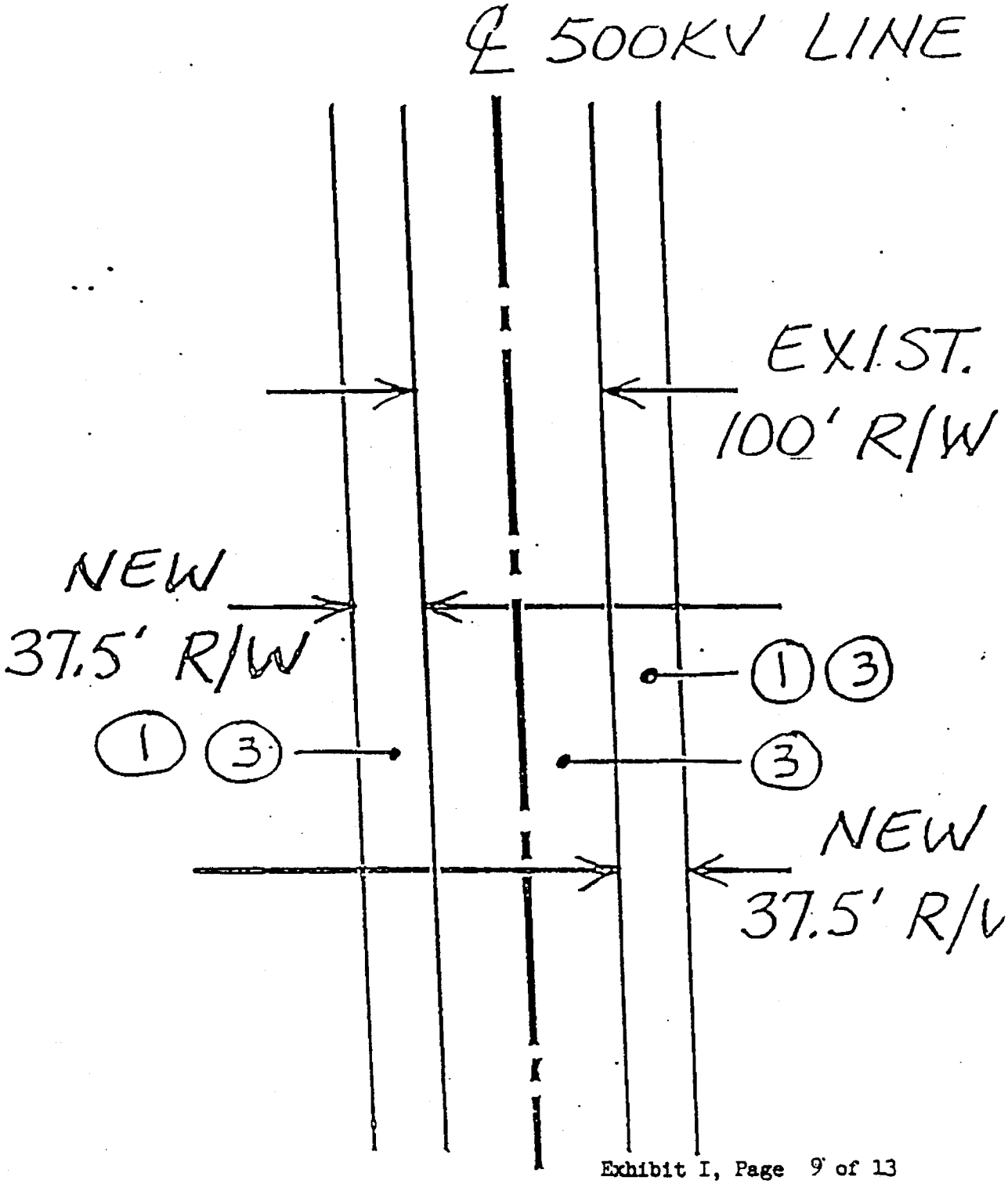
D. NEW R/W ON GOVERNMENT LANDS



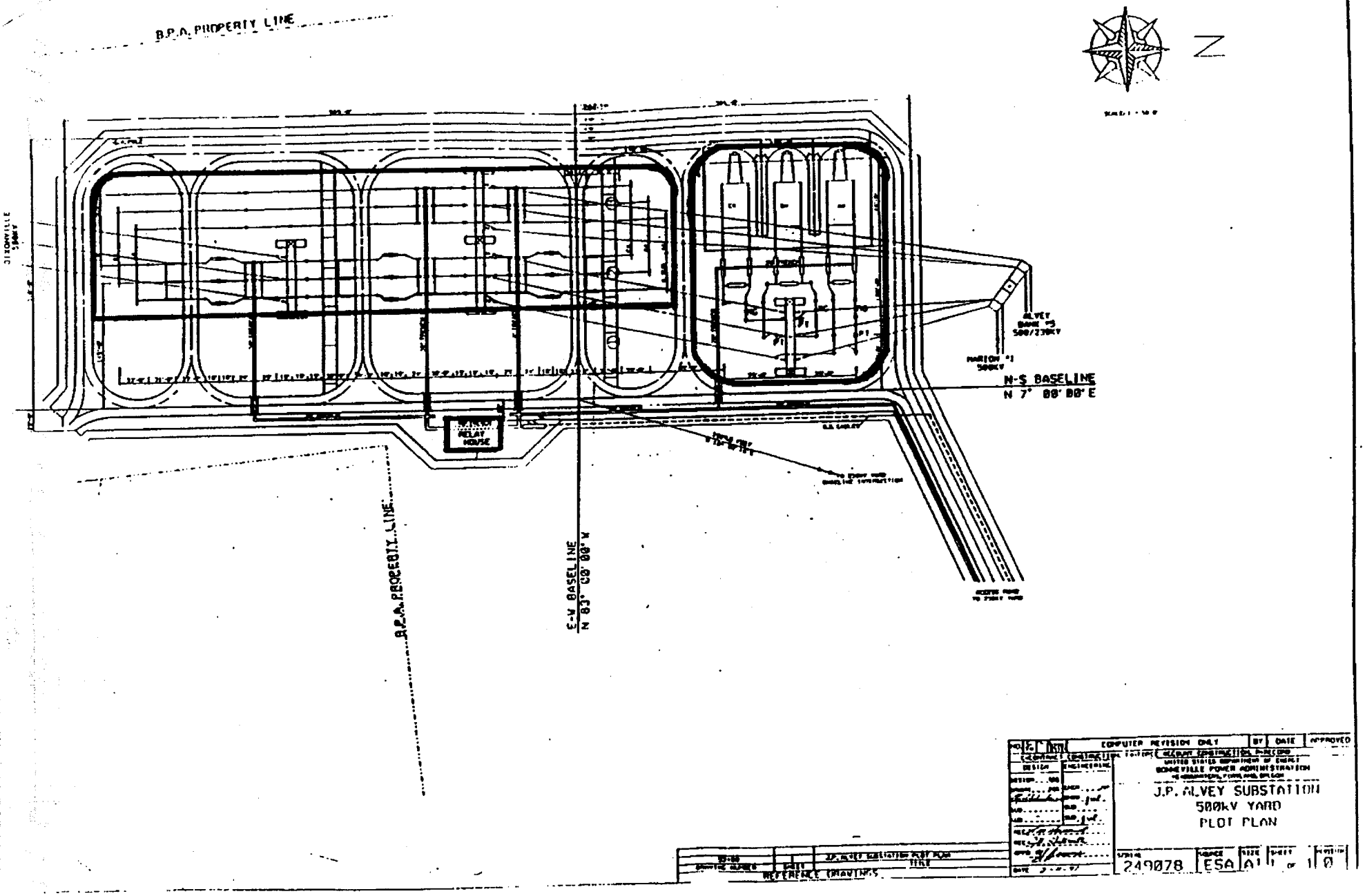
E. EXISTING R/W ON PP&L FEE OWNED LAND - (2)



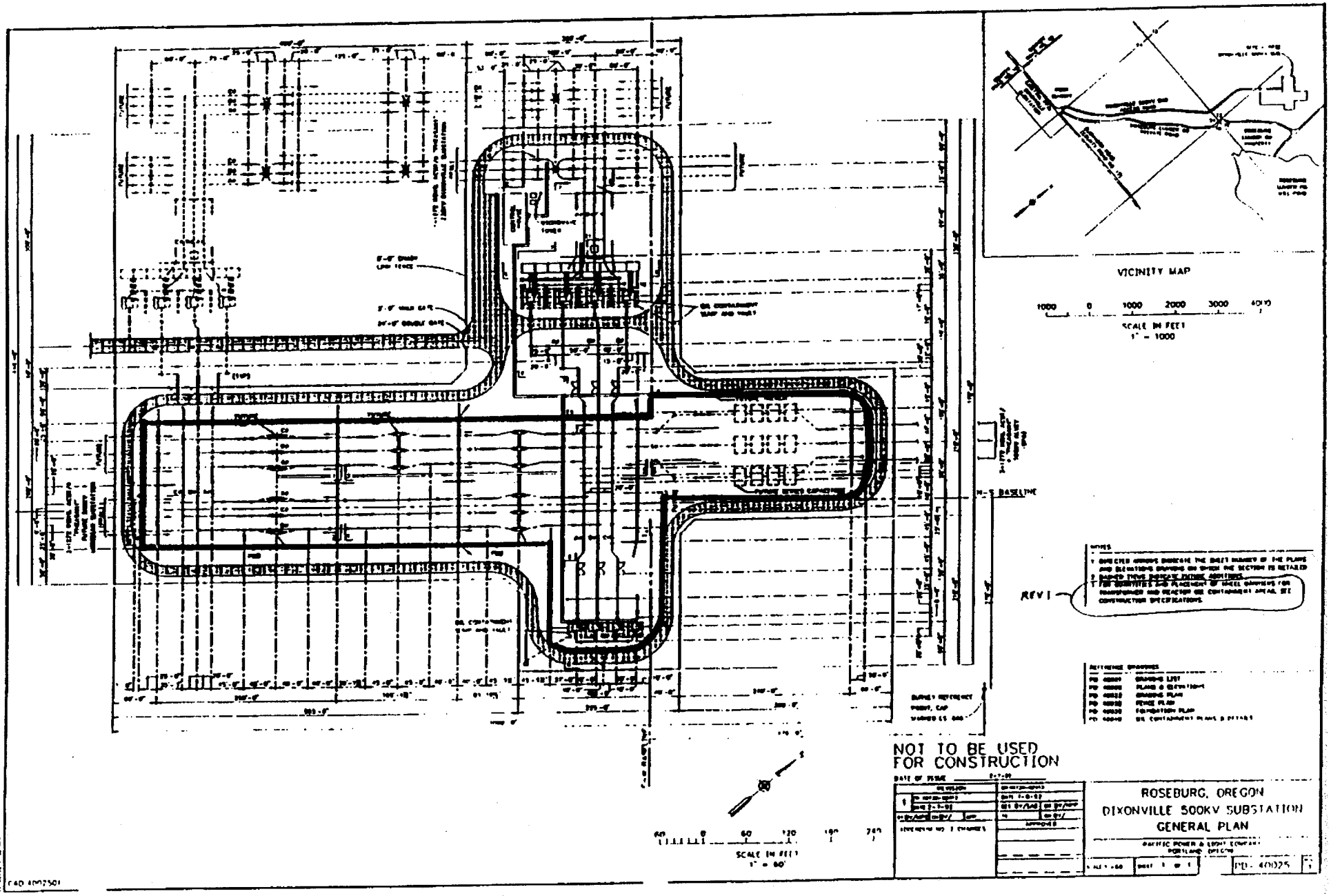
F. EXISTING R/W ON PRIVATE LAND - (2)



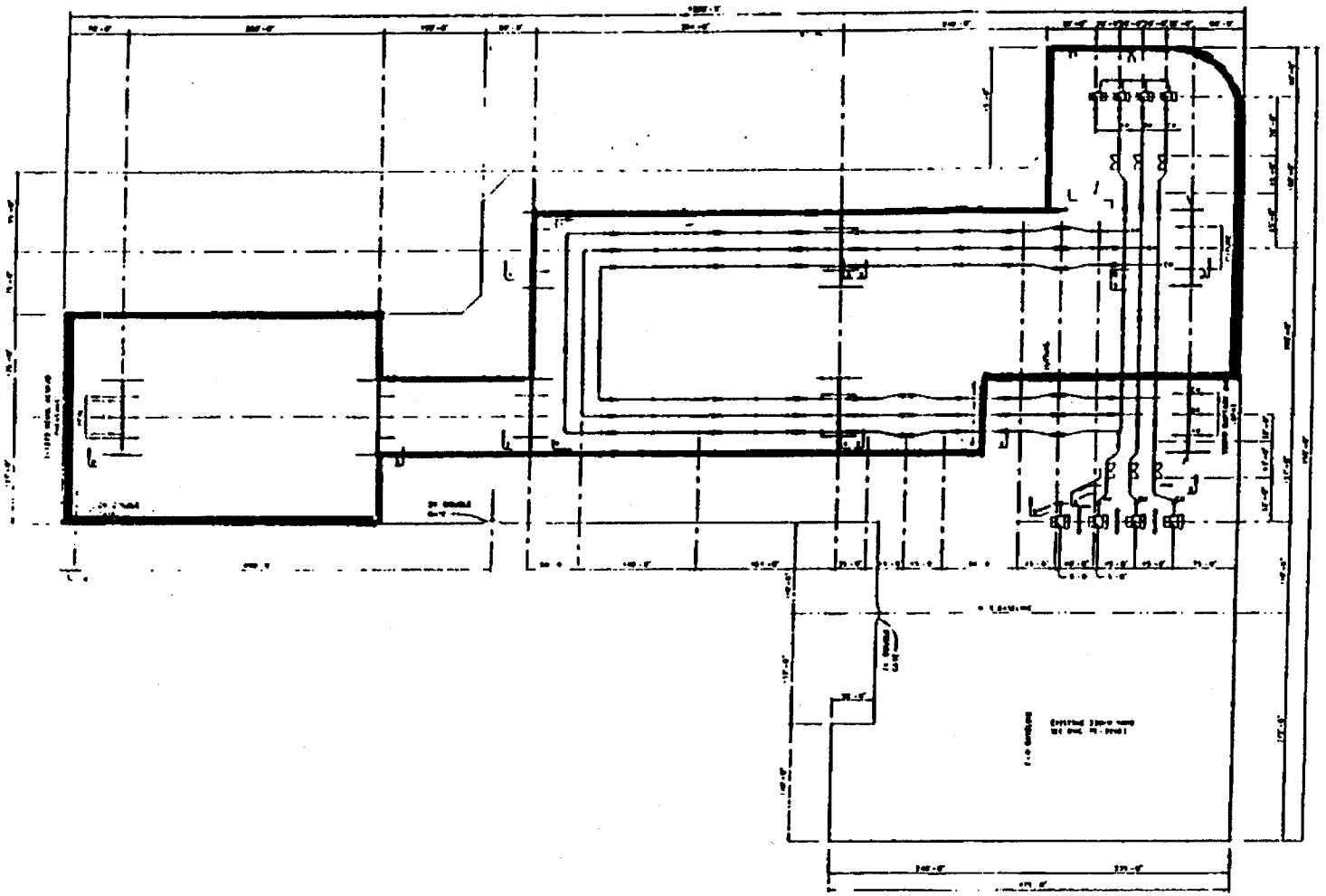
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date



Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date



Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

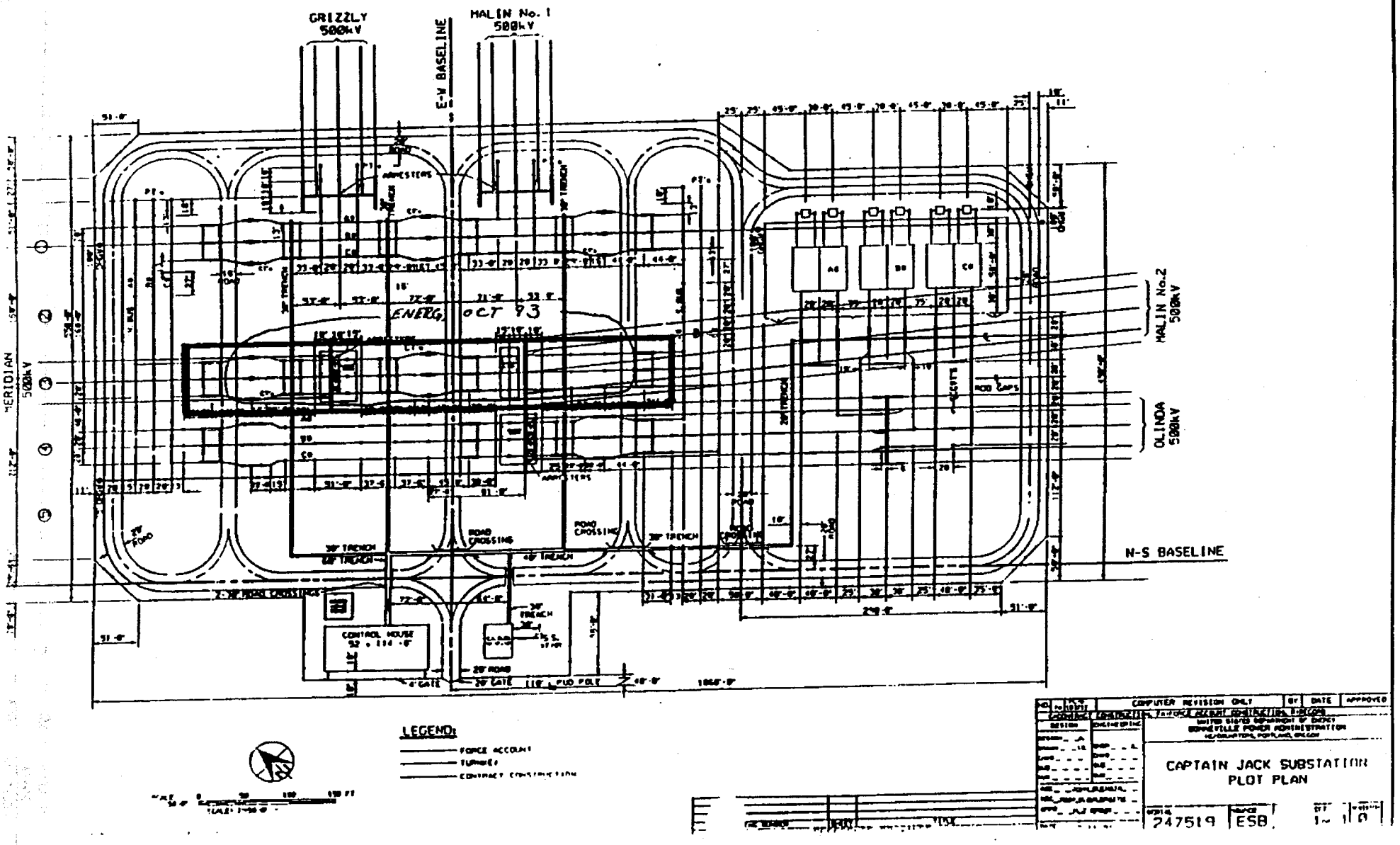


NOT TO BE USED
FOR CONSTRUCTION

MEDFORD, OREGON
MERIDIAN SUBSTATION
GENERAL PLAN

Amendatory Agreement No. 2
Contract No. DE-MS79-86BP92299
PacifiCorp
Effective at 2400 Hours
on the Effective Date

16:36:19 28-OCT-91 ZH0:[051.157]247519S01.DGN



Capital Replacements

Either Party shall be able to initiate Capital Replacement projects to be added under this Exhibit as additional tables.

Calculation of O&M Charges

Facilities	Annual Operation and Maintenance Charge 1/	Annual Payment Due From PacifiCorp
Alvey (3) 500 kV PCB Terminals x ($46,018 terminal) Monthly Charge = $5752	$138,054	$69,027 2/
Sycan New Series capacitor bank (546 MVAR) in The Summer Lake-Malin 500 kV Line Monthly Charge = $5290	$181,381	$63,483 2/

1/ O&M Cost: From Bonneville Power Administration's Annual O&M Charges for Customer-Owned or Leased Facilities dated September 30, 1991.
2/ Effective December 18, 1992

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Alvey Substation						
♦ 3-500 kV breakers/CT's, buswork, towers, MOD's, PT's, arresters, associated grounding, conduit, control and power cables, site dev. including landscaping, station service equipment for the 3 breaker ring bus layout.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Environmental related work.	Bonneville	50/50	N/A	N/A	N/A	
♦ Series capacitors and auxiliaries.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Property acquired for 500 kV yard for Intertie purposes, excluding any additions, for future BPA projects.	Bonneville	50/50	50/50	Bonneville	42/58	Requires identification of boundaries. O&M costs subject to non-routine work. BPA to maintain at 100% BPA costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
♦ 500 kV Relay House building.	Bonneville	50/50	50/50	Bonneville	42/58	Future BPA/PP&L expansion will be done at 100% BPA/PP&L costs, otherwise 50/50 if Intertie related. General building maintenance should be at BPA discretion with 42/58 cost sharing.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Relaying and controls, data system equip. inside the 500 kV Relay House for the Alvey-Dixonville, Marion-Alvey and 500 kV Tie Line.	Bonneville	50/50	50/50	Bonneville	42/58	BPA has future rights for BPA projects at 100% BPA costs otherwise 50/50 if Intertie related. O&M at 42/58 as per this Exhibit C for Intertie related facilities. BPA to maintain.
♦ RAS related equip.	Bonneville					Refer to Contract #93039.
♦ Metering/Telemetering equipment on the Alvey-Dixonville Line.	Bonneville	50/50	50/50	Bonneville	42/58	BPA to do the maintenance at BPA discretion.
500 kV Tie Line (Alvey 500-Tx. Bank #5)						
♦ Transmission related costs.	Bonneville	50/50	50/50	Bonneville	100/0	50/50 ownership means PP&L has 50% capacity rights on the Tie Line but not physical ownership. Transfer rights over Bank #5 are not covered here.
Marion-Alvey 500 kV Line Modifications						
♦ Transmission costs only. 1/	Bonneville	50/50	100/0	Bonneville	100/0	
34.5 kV Line Relocation						
♦ Transmission costs only. 1/	Bonneville	50/50	100/0	Bonneville	100/0	

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Alvey-Dixonville 500 kV Line						
♦ 1.4 mile Alvey-Spencer Tap Section. 2/	Pacific	50/50	50/50	Pacific	42/58	Applicable only to the ROW for Intertie purposes. Additional ROW at 100% BPA costs.
♦ Remaining 56.7 miles. 2/	Pacific	50/50	50/50	Pacific	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads must also be considered. Timber costs and revenues also to be included. 2/
Spencer Tap						
♦ Costs to reterminate the PP&L Alvey-Dix. 230 kV Line. 1/	Pacific	50/50	0/100	Pacific	0/100	
♦ Costs to reterminate the PP&L Alvey-Diamond Hill 230 kV Line. 1/	Pacific	0/100	0/100	Pacific	0/100	
Dixonville 500 kV Substation						
♦ 3-Breaker Ring Bus, 180 MVAR Reactor, arresters, grounding, conduit, control and power cables, site development, PT's, station service, isolating disconnect switches for 500 kV ring bus.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion).
♦ Series capacitors and auxiliaries.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion).

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ 500/230 kV Transformer and related 230 kV equipment. 1/	Pacific	0/100	0/100	Pacific	0/100	PP&L to maintain.
♦ Wetland mitigation and other environmental requirements.	Pacific	50/50	N/A	N/A	N/A	
♦ Property acquired for 500 kV yard for Intertie purposes, excluding any additional future PP&L projects and any property for PP&L's 500/230 kV transformer.	Pacific	50/50	50/50	Pacific	42/58	Requires identification of boundaries. O&M costs subject to non-routine work. PP&L to maintain at 100% PP&L costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
♦ 500 kV Control House building.	Pacific	50/50	50/50	Pacific	42/58	Future PP&L/BPA expansion will be done at 100% PP&L/BPA costs. Otherwise 50/50 if Intertie related. General building maintenance should be at PP&L discretion with 42/58 cost-sharing.
♦ Relaying and controls, data system equip.inside the 500 kV Control House, excluding that associated with PP&L's 500/230 kV transformer and 230 kV line position(s).	Pacific	50/50	50/50	Pacific	42/58	PP&L has future rights for PP&L projects at 100% PP&L costs. Otherwise 50/50 if Intertie related. O&M at 42/58 as per this Exhibit C for Intertie related facilities. PP&L to maintain.
♦ RAS related equipment.	Pacific					Refer to Contract #93039.
♦ Metering/Telemetering equipment on the Dixonville-Alvey Line.	Pacific	50/50	50/50	Pacific	42/58	PP&L to do the maintenance at PP&L discretion.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Dixonville-Meridian 500 kV Line						
♦ Transmission costs. 2/	Pacific	50/50	50/50	Pacific	42/58	Requires identification of specific properties upon which these percentages are applicable. Access roads/bridge must also be considered. Timber costs and revenues also to be included.
Hanna Tap Relocation						
♦ Transmission and switching modification costs. 1/	Pacific	50/50	0/100	Pacific	0/100	Ownership and O&M costs percentages reflect existing arrangements which will be maintained.
Table Rock Switching Station						
♦ Costs to remove existing station.	Pacific	50/50	N/A	N/A	N/A	Existing station is in the path of the new 500 kV Line.
♦ Costs to reconnect Line #71 to south portion of Line #54. 1/	Pacific	50/50	0/100	Pacific	0/100	
Meridian Substation						
♦ Installation of 2-500 kV breakers, CT's, 180 MVAR reactor, 2 Line PT sets, isolating disconnect switches, arresters, buswork, conduit, control and power cables, grounding, including site development for Intertie purposes.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion). 50/50 ownership does not apply to the existing property upon which such facilities lie.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Environmental related work associated with the 500 kV expansions required.	Pacific	50/50	N/A	N/A	N/A	
♦ Any additional new property required to support the project.	Pacific	50/50	50/50	Pacific	42/58	Requires identification of boundaries. O&M costs subject to non-routine work. PP&L to maintain at 100% PP&L costs, things like surface rock, sidewalks, roads, fenceline, aesthetics.
♦ Access road improvements or new access road.	Pacific	50/50	50/50	Pacific	0/100	
♦ Existing property. 1/	Pacific	0/100	0/100	Pacific	0/100	Boundaries to be identified that conveys future BPA rights of use.
♦ Series capacitors and auxiliaries.	Pacific	50/50	50/50	Pacific	42/58	PP&L to operate and maintain (including maintenance of conduit, trench and grounding systems at PP&L discretion).
♦ Data system equip. inside the existing 500 kV Control House associated with the 2 breakers, 180 MVAR reactor, and the Meridian-Dixonville and Meridian-Captain Jack Lines.	Pacific	50/50	50/50	Pacific	42/58	PP&L to maintain.
♦ Relaying and controls for the Meridian-Dixonville 500 kV Line.	Pacific	50/50	50/50	Pacific	42/58	PP&L to maintain.
♦ Relaying and controls for the Meridian-Captain Jack #2 500 kV Line. 1/	Pacific	50/50	0/100	Pacific	0/100	PP&L to maintain. BPA retains the right to review any future relay replacements/modifications.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Any modification to the existing Control House or construction of a new Control House as a result of the Eugene-Medford projects.	Pacific	50/50	50/50	Pacific	0/100	Future PP&L/BPA expansion will be done at 100% PP&L/BPA costs, other-wise 50/50 if Intertie related. PP&L to maintain at their discretion.
♦ Construction of a new storage building.	Pacific	50/50	50/50	Pacific	0/100	Use of building to be audited later to confirm cost sharing percentages.
♦ RAS related equipment.						Refer to Contract #93039.
Malin-Meridian 500 kV Line Loop Into Captain Jack Substation						
♦ Transmission line modifications. 1/	Pacific	50/50	0/100	Pacific	0/100	3/
Captain Jack Substation						
♦ Bay 3 facilities, including 2-500 kV breakers, 4-MOD's, buswork, PT's, conduit, grounding, towers.	Bonneville	50/50	0/100	Bonneville	0/100	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Property under Bay 3.	Bonneville	50/50	0/100	Bonneville	Prorate	Prorate based on 2/7. BPA to maintain.
♦ Relays and controls, data systems equip. for Bay 3 facilities.	Bonneville	50/50	0/100	Pacific	0/100	PP&L to maintain. BPA retains the right to review any future relay replacements/modifications.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Remaining 5-500 kV breakers, MOD's, buswork towers, conduit, grounding, site develop. 1/	Bonneville	100/0	100/0	Bonneville	100/0	BPA to operate and maintain (including maintenance of conduit, trench and grounding systems at BPA discretion).
♦ Station service facilities for the entire station. 1/	Bonneville	100/0	100/0	Bonneville	Prorate	Prorate based on 2/7. BPA to maintain.
♦ Remaining relays and controls, data system equipment. 1/	Bonneville	100/0	100/0	Bonneville	100/0	BPA to maintain.
♦ Control House, exclusive of the property upon which it lies. 1/	Bonneville	100/0	100/0	Bonneville	100/0	Any future expansions due to PP&L additions will be at 100% PP&L costs but BPA to retain 100% ownership.
♦ All remaining property including access road. 1/	Bonneville	100/0	100/0	Bonneville	100/0	Requires identification of boundaries. PP&L has right to add transformer in future.
♦ Series capacitors. 1/	Bonneville	100/0	100/0	Bonneville	100/0	Cost sharing/ownership is with TANC as per Interconnection Agreement (short or long term, whatever prevails). BPA to maintain.
♦ RAS related equipment.						Refer to Contract #93039.
♦ Metering/Telemetering equipment on the Captain Jack-Meridian and Captain Jack-Malin #2 Lines.	Bonneville	50/50	0/100	Bonneville	0/100	BPA to do the maintenance at BPA discretion.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Malin Substation						
♦ Any modifications/additions in PP&L's Control House in support of the Eugene-Medford/Third AC Intertie project, which includes the relay replacement for the Malin-Captain Jack Line. 1/	Pacific	50/50	0/100	Pacific	0/100	BPA retains the right to review any future relay replacements and/or modifications.
♦ Replacement of arresters on PacifiCorp's 500 kV reactor bank No. 4. 1/	Pacific	0/100	0/100	Pacific	0/100	
♦ Replacement of rod gaps with arrestors on PacifiCorp's C.J. Line terminal. 1/	Pacific	50/50	0/100	Pacific	0/100	
♦ RAS related equipment.						Refer to Contract #93039.
♦ Any modifications in main control house.	Bonneville	50/25	50/25	Bonneville	50/25	
♦ Relay replacement for the Summer Lake line.	Pacific	50/50	0/100	Pacific	42/58	Refer to Contract #93644.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
Line Relays at Dixonville, Meridian, and Malin and Related Accessories						
♦ Line relays at Dixonville, Meridian, and Malin for the Dixonville-Alvey, Dixonville-Meridian, Meridian-Captain Jack, and Malin-Captain Jack #2 Lines are to be supplied to PP&L at BPA material cost plus BPA overheads. Any additional PP&L overheads, subject to 50/50 cost share, is to be determined.	Pacific	50/50	See Comments			Ownership and O&M of such relays are as described under the respective substations.
♦ Spare Equipment.	Bonneville	50/50	50/50	N/A	N/A	Reference 7/12/91 Letter from Don Feltz to Susan Wiese. Such spare equipment are to be located at PP&L station(s) in Southern Oregon. In addition to that referenced in the 7/12/91 Letter, there may be other spare equipment supplied by PP&L also located in S. Oregon and subject to cost-share. Required test equipment and tools are to be 100% respectively acquired by either BPA or PP&L for 100% discretionary use.
♦ Specialized relay training costs. 1/	N/A	50/50	N/A	N/A	N/A	Cost sharing only if agreed to capitalize such costs.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
General PSC Modifications						
♦ PSC Modifications at Dittmer and ECC will be 100% BPA and similarly PSC modifications at PP&L control centers will be 100% PP&L.	100% respectively	100% respectively	100% respectively	100% respectively	100% respectively	
♦ Any other modifications at other wholly-owned substations will be 100% of the respective party.	100% respectively	100% respectively	100% respectively	100% respectively	100% respectively	
Summer Lake Substation						
♦ Relay replacement for the Summer Lake-Malin 500 kV Line.	Pacific	50/50	0/100	Pacific	42/58	Refer to agreement #93644.
♦ RAS related equipment.						Refer to Trust Tables 18 & 19, Contract # 37013.
♦ Replacement of rod gaps with arrestors on PacifiCorp's Malin Line terminal. 1/	Bonneville	100/0	0/100	Pacific	0/100	
Sycan Series Compensation Station						
♦ New series capacitor bank in the S. Lake-Malin 500 kV Line.	Bonneville	65/35	65/35	Bonneville	65/35	Refer to agreement #93644.
♦ Bypass switch and associated support structures and foundations.	Bonneville	65/35	0/100	Bonneville	0/100	Refer to agreement #93644.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Dead-End tower.	Pacific	65/35	0/100	Pacific	0/100	Refer to agreement #93644.
Capital Spare Parts						
♦ Various spare parts.		50/50	50/50		42/58	Capital spare parts subject to cost sharing and joint ownership are to be mutually agreed upon and consistent with this agreement.
Overall Planning, Preliminary Engineering, Project Management						
Related costs for the Eugene-Medford Project, including any costs to resolve/mitigate legal matters (e.g., spotted owl and union vs. non-union issues).		50/50	50/50			
Communication:						
♦ Summer Lake-Malin Communication, Two Downlinks. 1/	Pacific	50/50	0/100	Pacific	0/100	Refer to the Sycan Agreement Contract No. DE-MS79-92BP93644 and Cooperative Communications Agreement Contract No. DE-MS79-92BP93740.
♦ Dixonville - Two Microwave Terminals. 1/	Pacific	50/50	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement Contract No. DE-MS79-92BP93740.

Facility Description	Design	Cost Share Percentage Bonneville/ Pacific	Ownership Percentage Bonneville/ Pacific	Operation & Maintenance	Operation & Maintenance Payments % Bonneville/ Pacific	Comments
♦ Meridian - Two Microwave Terminals 1/	Pacific	50/50	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.
♦ All Other Bonneville Communication Facilities.	Bonneville	100/0	100/0	Bonneville	100/0	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740
♦ Other Pacific Communication Facilities	Pacific	0/100	0/100	Pacific	0/100	Refer to the Cooperative Communications Agreement, Contract No. DE-MS79-92BP93740.

1/ Credits and sharing of costs for capital replacements will not be applicable to this item after completion of the initial construction. Proceeds from credits realized by either Party during the initial construction phase of this item shall be subject to cost-share and the final accounting of costs.
2/ Costs of (1) removal of any existing 230 kV facilities; (2) permitting; and (3) incremental right-of-way to be included.
3/ Includes procurement of right-of-way from Meridian-Malin transmission line structures to Captain Jack Substation.

(7664-PMT-W:\CONTRACT\EXH\WP3598EE.DOC)

FACILITIES SERVING PACIFICORP'S LOAD AREA

PacifiCorp's Load Area is the area serviced by the following existing transmission lines and transformers.

1. PacifiCorp's Malin 500-230 kV transformer.
2. PacifiCorp's Yamsey-Chiloquin 230 kV line.
3. PacifiCorp's Dixonville 500-230 kV transformer.
4. PacifiCorp's Alvey-Dixonville 230 kV line.
5. PacifiCorp's Reston-Dixonville 230 kV line.
6. PacifiCorp's Meridian 500-230 kV transformer.

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

AUG 16 1991

In reply refer to:
PMTI

Amendment No. 1
Contract No. DE-MS79-86BP92299

Mr. Thomas Lockhart, Vice President
Power Systems
PacifiCorp Electric Operations
920 SW. Sixth Avenue
Portland, OR 97208

Dear Mr. Lockhart:

Pursuant to subsection 4(a) of Contract No. DE-MS79-86BP92299, as amended, (Intertie Agreement) between PacifiCorp Electric Operations (Pacific) and Bonneville Power Administration (Bonneville), Bonneville hereby provides Pacific notice that, effective on the Effective Date, Bonneville is exercising its option to acquire a fifty percent undivided ownership interest in the Alvey-Meridian Line, as defined in such agreement and as modified herein. Pacific and Bonneville hereby agree to amend the Intertie Agreement by supplementing it with the following provisions, and replacing Exhibit C to such agreement with the attached Revision No. 1 to such Exhibit.

1. Completion of the Alvey-Meridian 500 kV Line.

(a) Design and Construction. Pacific and Bonneville shall use best efforts to complete the Alvey-Meridian Line by November 1993. Pacific shall design and construct the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including series capacitors, and the Alvey-Dixonville portion of the Alvey-Meridian Line (Alvey-Dixonville Line) and the Dixonville-Meridian portion of the Alvey-Dixonville Line (Dixonville-Meridian Line). Bonneville shall design and construct the Alvey 500 kV Substation (Alvey Substation) including the Alvey Substation series capacitors. The Parties shall seek opportunities to utilize the capabilities of the other to minimize the installed cost and operation and maintenance cost and maintain schedules. The Parties shall agree at a later date upon the prudent design and construction of the Dixonville-Meridian Line, Dixonville 500 kV Substation series capacitors, and the Meridian Substation series capacitors. Each Party shall have the right to comment on the design and construction to be performed by the other Party.

(b) Maintenance and Operation. Pacific shall assume system operation and maintenance responsibilities of the Dixonville 500 kV Substation including the series capacitors, the terminal facilities at Meridian Substation for the Dixonville-Meridian Line including the series capacitors, and the Alvey-Meridian Line. Bonneville shall assume system operation and maintenance responsibilities of the Alvey Substation including the series capacitors. The Parties shall jointly develop maintenance standards and responsibilities that seek to limit the total annual operation and maintenance charges. Payment for operation and maintenance costs associated with these facilities shall be as specified in the Intertie Agreement, including Revision No. 1 to Exhibit C.

(c) Ownership.

(1) Pacific and Bonneville shall have undivided joint ownership of the Alvey-Meridian Line based upon the ownership percentages specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(2) Pacific and Bonneville shall have undivided joint ownership of incremental land acquisitions necessary to complete the Alvey-Meridian Line. Pacific shall convey to Bonneville any rights of use of Pacific's existing land sufficient to allow Bonneville to facilitate use of its right to fifty percent of the Incremental Capacity and ownership.

(3) The transfer of property titles (equipment, land, etc.) by the Parties in order to provide for undivided joint ownership shall occur at the time of energization of the Alvey-Meridian Line.

(4) Ownership of the communications systems shall be determined in accordance with section 6.

(d) Expansion of Facilities.

(1) Pacific shall have the right to modify the Dixonville 500 kV Substation and Meridian Substation, at its expense, as necessary for future required facilities without agreement by Bonneville, provided that Bonneville's ownership right to fifty percent of the Incremental Capacity of the Alvey-Meridian Line, as defined in the Intertie Agreement (Incremental Capacity), is not diminished.

(2) Upon expiration of the Intertie Agreement, Bonneville shall have the right to make additional facility connections at the Meridian Substation, at its expense, to facilitate use of its right to fifty percent of the Incremental Capacity, provided that such new connections do not increase loadings on Pacific's exclusively-owned facilities, diminish Pacific's rights to the Alvey-Meridian Line, or adversely impact Pacific's system.

(3) Bonneville shall have the right to modify the Alvey Substation, at its expense, as necessary for future required facilities without agreement by Pacific, provided that Pacific's ownership right to fifty percent of the Incremental Capacity is not diminished.

(4) Upon expiration of the Intertie Agreement, Pacific shall have the right to make additional facility connections at the Alvey Substation, at its expense, to facilitate use of its fifty percent share of the Incremental Capacity, provided that such new facility connections do not increase loadings on Bonneville's exclusively owned facilities, diminish Bonneville's rights to the Alvey-Meridian Line, or adversely impact Bonneville's system.

(e) Cost Sharing/Payment. Cost sharing for design and construction of the Alvey-Meridian Line shall be as specified in Revision No. 1 to Exhibit C. The Parties agree to develop mutually agreeable terms and conditions for payment for design and construction of the line. Such terms and conditions shall include provisions for progress payments, recognition of any payments made by either Party, or expenses incurred by either Party that are associated with the interim agreements (Contract Nos. DE-MS79-90BP92901, DE-MS79-91BP93112, DE-MS79-91BP93112, and DE-MS79-90BP93070) between the Parties as replaced by this amendment.

2. Alvey Substation 500 kV Terminal. Contract No. DE-MS79-90BP92901 shall terminate as of the Effective Date of this amendment.

3. Captain Jack Substation Connection/Terminal.

(a) Contract No. DE-MS79-91BP93112 shall terminate as of the Effective Date of this amendment.

(b) Pacific and Bonneville agree to equally share the cost of the following work performed by Pacific:

(1) procurement of the right-of-way from the Meridian-Malin transmission line structures to Captain Jack Substation;

(2) design and construction of the new 500 kV transmission line from Meridian-Malin 500 kV line structures to the Captain Jack Substation dead end towers;

(3) removal of certain Meridian-Malin 500 kV transmission line facilities; and

(4) design and construction of the strain bus connection between the Captain Jack dead end towers in Bay 3 to connect the Meridian-Malin line segments.

(c) Pacific and Bonneville agree to equally share the cost of the following work performed by Bonneville:

(1) design and construction of Captain Jack Substation dead end structures at Bay 3; and

(2) design and construction of power circuit breakers and associated Bay 3 terminal equipment including relays, and facilities to connect the Meridian-Malin line.

(d) Pacific shall own the land, right-of-way, power circuit breakers, terminal equipment including relays, and facilities up to the dead end towers, the dead end towers, and the strain bus between such towers at Bay 3.

(e) Bonneville shall assume system operation and maintenance responsibilities for all facilities at Captain Jack Substation except terminal Bay 3 relays and communications owned by Pacific, which shall be assumed by Pacific.

4. Sycan.

(a) The following provisions of Contract No. DE-MS79-91BP93157 shall terminate as of the Effective Date of this amendment:

(1) payment provisions specified in Section 4 and Exhibit A;

(2) cost sharing provisions specified in Sections 5 and 6; provided, however, the duties of the Parties described in such Sections shall remain; and

(3) ownership provisions specified in Section 7; provided, however, Pacific shall own the protective relays for the Summer Lake-Malin terminals pursuant to Revision No. 1 to Exhibit C of the Intertie Agreement.

(b) Contract No. DE-MS79-90BP93070 shall terminate as of the Effective Date of this amendment.

(c) Bonneville shall design and construct the series capacitors. Bonneville shall pay the design and construction costs and own the series capacitors until the Parties reach agreement pursuant to subsection 4(f) below.

(d) Bonneville shall operate and maintain the Sycan Compensation Station, including the series capacitors and bypass switch and associated structures; provided, however, the Summer Lake-Malin terminal relays shall be operated and maintained by Pacific. Payment for such operation and maintenance costs shall be as specified in Revision No. 1 to Exhibit C of the Intertie Agreement.

(e) The Sycan dead end tower shall be operated and maintained by Pacific.

(f) The Parties shall mutually agree to the terms and conditions for cost sharing for the Sycan series capacitors, bypass switch and

associated structures, Summer Lake-Malin terminal relays, Summer Lake-Malin communications down-link, and dead end tower.

5. Coordinated Operations. The Parties shall jointly develop coordinated operating procedures for the Alvey-Meridian Line, Captain Jack Substation, and Sycan Compensation Station such that Bonneville may adequately perform as the system operator for the combined AC Intertie, and that maximize the Operational Transfer Capability of the AC Intertie and maximize Pacific's capability to serve its southern Oregon and northern California loads pursuant to Section 5(d)(2)(A) of the Intertie Agreement.

6. Communications. The Parties are in substantial agreement as to the terms, conditions, and ownership associated with requirements for communication facilities and equipment described herein, and shall complete such terms and conditions as soon as practicable following execution of this amendment. Such terms and conditions shall be incorporated in a separate agreement.

7. Liability. The Parties agree that if any injunction is issued by a court of competent jurisdiction against either Party's implementation of this amendment, such injunction shall not constitute a basis for a breach of contract action.

8. Effective Date. This amendment shall be effective on the later of:

(a) the issuance of a biological opinion by the United States Fish and Wildlife Service regarding the northern spotted owl which is acceptable to both Parties; or

(b) the date Bonneville receives a copy of this amendment signed by Pacific (Effective Date).

If this amendment is acceptable to Pacific, please sign and return one copy to Bonneville. The remaining copy is for your files. Please have your staff

contact Allen Burns, at (503) 230-3367, to establish a schedule for discussions made necessary by the execution of this amendment.

Sincerely,

Administrator

ACCEPTED:

PACIFICORP ELECTRIC OPERATIONS

By _____
Thomas A. Lockhart

Title Vice President

Date August 16, 1991

Effective Date November 18, 1991

(VS6-PMTI-6802d)

INVESTMENT ALLOCATIONS

Facility	Design	Cost Share % Bonneville/Pacific	Ownership % Bonneville/Pacific	Operation	Maintenance	O&M Payment % Bonneville/Pacific
A. Alvey-Meridian Line:						
• Alvey 500 kV Substation						
– 3 PCB's	Bonneville	50/50	50/50	Bonneville	Bonneville	42/58
• Alvey-Dixonville 500 kV Line 1/	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Dixonville 500 kV Substation						
– Transformer	Pacific	0/100	0/100	Pacific	Pacific	0/100
– 3 PCB's	Pacific	50/50	50/50	Pacific	Pacific	42/58
– 1 180 MVAR Reactor	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Dixonville-Meridian 500 kV Line 1/	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Terminal Facilities for Dixonville-Meridian Line at Meridian 500 kV Sub						
– 2 PCB's	Pacific	50/50	50/50	Pacific	Pacific	42/58
– 1 180 MVAR Reactor	Pacific	50/50	50/50	Pacific	Pacific	42/58
• Series Capacitors						
– Alvey	Bonneville	50/50	50/50	Bonneville	Bonneville	42/58
– Dixonville	Pacific	50/50	50/50	Pacific	Pacific	42/58
– Meridian	Pacific	50/50	50/50	Pacific	Pacific	42/58
B. Captain Jack Substation Bay 3 Terminal Facilities and Loop Line:						
• 500 kV Line Meridian-Malin to Captain Jack Substation 2/	Pacific	50/50	0/100	Pacific	Pacific	0/100
• Bay 3 Dead End Towers	Bonneville	50/50	0/100	Bonneville	Bonneville	0/100
• Power Circuit Breakers and Terminal Equipment Bay 3	Bonneville	50/50	0/100	Bonneville	Bonneville	0/100
• Relays	Bonneville	50/50	0/100	Pacific	Pacific	0/100

INVESTMENT ALLOCATIONS

Facility	Design	Cost Share Bonneville/Pacific	Ownership Bonneville/Pacific	Operation	Maintenance	O&M Payment % Bonneville/Pacific
A. System:						
• Relay Replacement - Summer Lake-Malin Terminals	Pacific	3/	0/100	Pacific	Pacific	42/58
• Series Capacitors	Bonneville	3/	4/	Bonneville	Bonneville	100/0
• Bypass Switch and Associated Support Structures and Foundations	Bonneville	3/	0/100	Bonneville	Bonneville	0/100
• Dead-End Tower	Pacific	3/	0/100	Pacific	Pacific	0/100
B. Communications:						
• Summer Lake-Malin Communication Downlink	Pacific	5/	0/100	Pacific	Pacific	0/100
• All other communications 5/						

1/ Costs of (1) removal of any existing 230 kV facilities; (2) permitting; and (3) incremental right-of-way to be included.
2/ Includes procurement of right-of-way from Meridian-Malin transmission line structures to Captain Jack Substation.
3/ To be determined pursuant to subsection 4(f).
4/ To be determined pursuant to subsection 4(c).
5/ All other communications arrangements to be determined pursuant to section 6.

CALCULATION OF LOSSES

Pursuant to Section 10 of the Letter of Understanding dated May 28, 1993, Bonneville and PacifiCorp have conducted a joint study of electrical losses related to AC Intertie transactions. Representatives of Bonneville and PacifiCorp jointly issued a letter dated April 21, 1994, which stated the conclusions reached as a result of this study. The treatment of electrical losses related to AC Intertie transactions shall be in accordance with the April 21, 1994 letter as summarized below.

Bonneville shall return losses to PacifiCorp. Such return of losses shall be calculated as 0.2 percent (0.2%) of Bonneville's Net AC Intertie Schedule, and shall be scheduled to PacifiCorp 168 hours later. "Bonneville's Net AC Intertie Schedule," means the net of all AC Intertie schedules, other than PacifiCorp's schedules associated with its Northbound and Southbound ownership rights in the AC Intertie. Returned losses shall be scheduled from Bonneville to PacifiCorp's main system points of delivery, or as otherwise agreed by the Parties.

EXAMPLE

On a given hour:

Net AC Intertie Schedule is 4,800 MW

PacifiCorp's Schedule over its AC Intertie capacity is 400 MW

Bonneville's Net AC Intertie Schedule is:

4,800 MW - 400 MW = 4,400 MW

Loss to be scheduled to PacifiCorp 168 hours later:

4,400 MW x 0.2% = 8.8 MW

AUTHENTICATED

Service Agreement No. 98TX-10172

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
TRANSALTA ENERGY MARKETING (U.S.), INC. - TEMUS

Index

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Exhibits	
Exhibit A	(Open Access Transmission Tariff)
Exhibit B	(Application for Point-to-Point Transmission Service)
Exhibit C	(Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit D	(System Impact Study Agreement)
Exhibit E	(Facilities Study Agreement)
Exhibit F	(Wholesale Power and Transmission Rate Schedules)
Exhibit G	(Facilities Charges)
Exhibit H	(Ancillary Services)
Exhibit I	(Transmission Scheduling Provisions)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 26th day of August 1998, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and TransAlta Energy Marketing (U.S.), Inc. – TEMUS (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are

sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

W I T N E S S E T H :

WHEREAS the Parties are interconnected directly or through their Designated Agent(s) with each other and/or with other electric utility systems; and

WHEREAS BPA provides Point-to-Point (PTP) Transmission Service under BPA's Open Access Transmission Tariff (Tariff);

NOW, THEREFORE, in consideration of the promises and mutual covenants and agreements herein contained, the Parties do agree as follows:

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 **Terms and Conditions.** BPA agrees to provide and the Transmission Customer agrees to take and pay for PTP Transmission Services in accordance with the provisions of this Service Agreement and the Tariff. The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this reference and made a part of this Service Agreement as Exhibit A. BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 **Application.** The Application for PTP Transmission Service requested by the Transmission Customer and accepted by BPA for this Service Agreement is hereby incorporated and made a part of this Service Agreement as Exhibit B.

1.3 **Statement of Specifications for Long-Term Firm Transmission Service.** The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual

transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit C and made applicable to that transaction.

1.4 **System Impact/Facilities Study Agreements.** Study Agreements for a System Impact Study and/or a Facilities Study, if performed for any Application, are hereby incorporated as Exhibits D and E, respectively, and made applicable to those transactions.

1.5 **Wholesale Power and Transmission Rates Schedules.** BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated as Exhibit F.

1.6 **Facilities Charges.** All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit G.

1.7 **Ancillary Services.** The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit H.

1.8 **Transmission Scheduling Provisions.** The Transmission Scheduling Provisions are hereby incorporated as Exhibit I.

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 2400 hours on August 5, 1998. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on

August 4, 2003; or (b) two years after the Transmission Customer provides written notice of termination pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 **Charges for Transmission Service.** The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the rate schedules as specified below.

4.1.1 PTP Transmission Rate (PTP-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.2 Ancillary Products and Services Rate (APS-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.3 Reserved Nonfirm Transmission Rate (RNF-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.4 Energy Transmission Rate (ET-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.5 Advance Funding Rate for facilities listed in Exhibit G (AF-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.6 Use-of-Facilities Rate for facilities listed in Exhibit G (UFT-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.7 Southern Intertie Rate (IS-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.1.8 Montana Intertie Rate (IM-96, or its successor) listed in the Wholesale Power and Transmission Rate Schedules.

4.2 **Billing and Payment.** Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and shall be payable in accordance with the Tariff.

4.3 **BPA Appropriations Refinancing Act, Public Law 104-134.** The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Agreement.

ARTICLE 5
NOTICES

5.1 **Notices Relating to Provisions of the Service Agreement.** Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If the notice is to the Transmission Customer:

Attn: Contracts Administrator
TransAlta Energy Marketing (US), Inc. - TEMUS
Box 1900, Station "M"
110-12th Avenue S.W.
Calgary, Alberta
T2P 2M1
Phone: (403) 267-6988
Fax: (403) 267-6907

If the notice is to BPA:

Transmission Account Executive for
TransAlta Energy Marketing (US), Inc. - TEMUS
Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666-0491

5.2 **Notices of an Operating Nature.** Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified transmission service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 **Interconnection with Other Systems.** Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 **Governing Law.** This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3. **Amendments.** Except as provided in Articles 1.1, 6.4 and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 **Tariff Revisions.** In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than 60 days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within 30 days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within 30 days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the transmission service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.5 **Revision of Exhibits.** If any changes to Exhibits C, D, E, F, G, H, or I are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. Except for changes pursuant to Article 6.5.3, the Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.5.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit C pursuant to this Service Agreement, BPA shall prepare a revised Exhibit C. BPA reserves the

unilateral right to amend contiguous point of delivery provisions in Exhibit C of this Service Agreement.

6.5.2 If the Parties execute agreements for a System Impact Study and/or Facilities Study under this Service Agreement, BPA shall prepare a revised Exhibit D and/or Exhibit E.

6.5.3 BPA may change the rates that apply to Transmission Service under this Service Agreement pursuant to applicable law. BPA shall prepare a new Exhibit F.

6.5.4 If the Parties agree to change Exhibit H, BPA shall prepare a new Exhibit H. BPA reserves the right to update the loss factors identified in Exhibit H, section 2, Transmission Loss Factors.

6.5.5 For changes to any of the provisions contained in the Transmission Scheduling Provisions Exhibit (Exhibit I) to reflect current practice, BPA shall prepare a new Exhibit I.

6.6 **Temporary Load Shifts and Maintenance Notification.** The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within 4 days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The

point of contact for each Party will be designated pursuant to Article 5.2 of this Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within 4 days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.7 **Severability.** In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.8 **Computation of Time.** To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.9 **No Third Party Beneficiaries.** This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.10 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in

connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.11 **Successors and Assigns.** This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.12 **Service Agreement Governs.** In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.13 **Designation of Party Subject to Reciprocal Service Obligation.** To the extent that the Transmission Customer or its affiliate owns transmission facilities, the Transmission Customer and its affiliate are subject to reciprocal service obligation.

6.14 **Entire Agreement.** This Service Agreement constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

IN WITNESS WHEREOF, the duly authorized representatives of BPA and the Transmission Customer have executed this Service Agreement as of the date first above written.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ KIPPEN R. MOXNESS

Name: Kippen R. Moxness

Title: Transmission Account Executive

Date: July 31, 1998

TRANSALTA ENERGY MARKETING (US), INC. - TEMUS

By: /S/ ED DE PALEZIEUX

Name: Ed de Palexieux
(Print or Type)

Title: Manager, Real Time Trading

Date: Aug. 26/98

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OPEN ACCESS TRANSMISSION TARIFF

BPA's PTP Tariff shall constitute this Exhibit A until such time as the Commission approves BPA's Open Access Transmission Tariff.

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APPLICATION FOR PTP TRANSMISSION SERVICE

(Not applicable at this time)

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STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

(Not applicable at this time)

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SYSTEM IMPACT STUDY AGREEMENT

A System Impact Study is not required at this time for the service under this Service Agreement.

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FACILITIES STUDY AGREEMENT

A Facilities Study is not required at this time for the service under this Service Agreement.

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WHOLESALE POWER AND TRANSMISSION RATE SCHEDULES

(Reference the 1996 Wholesale Power and Transmission Rate Schedules or its successor)

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FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

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ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL)	98TX-10172
(b)	**Energy Imbalance**		
(c)	**Control Area Reserves for Resources**		
(d)	**Control Area Reserves for Interruptible Purchases**		
(e)	**Load Regulation**		
(f)	**Reactive Supply and Voltage Control**		
(g)	**Transmission Losses**	BPA(TBL)	98TX-10172

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) Transmission Losses Associated with Federal Power. Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules, are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power. The Transmission Customer shall compensate BPA for losses BPA incurs when providing transmission service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be determined by multiplying the amount of power delivered under this

Service Agreement by the applicable Loss Factor listed below in section 2; and

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) Transmission Losses Associated with Delivery Facilities. Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year 1/, pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

---

1/ Fiscal Year is defined as the twelve-month period from October 1 through September 30.

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e.

fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) Notification.

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer shall choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice for compensating BPA for transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit H.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate on the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year:

The Transmission Customer has elected to purchase Transmission Losses, pursuant to the APS-96 rate schedule, at a rate of **22.80** mills per kWh for the period 2400 hours August 5, 1998, through 2400 hours September 30, 1998.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit H as appropriate, but not more frequently than once in a 12-month period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit H incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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TRANSMISSION SCHEDULING PROVISIONS

1. PURPOSE OF THIS EXHIBIT

The purpose of this exhibit is to describe how the Parties will effect transmission transactions under this Service Agreement. The details of requesting and scheduling transmission can be found in the Transmission Scheduling Procedures posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPA

The Transmission Scheduling Procedures may be revised by BPA from time-to-time to reflect changes in business practices.

2. SCHEDULING AGENT DESIGNATION

(a) A single Designated Scheduling Agent (Scheduling Agent) will act in all capacities for the Transmission Customer to access the transmission system. All schedules and schedule changes must be submitted in the name of the Scheduling Agent. This is a yearly designation for the October through September time period.

(b) Any Transmission Customer or its Scheduling Agent using a Host Control Area (HCA), as defined by NERC, other than BPA must establish and verify transmission schedules with other Control Areas through the HCA, but the HCA is responsible for implementing and assuring the accuracy of the transmission schedule.

(c) Any Transmission Customer or its Scheduling Agent must arrange for wheeling across BPA's Control Area with affected parties to/from the agreed upon Points of Interconnection/Delivery consistent with BPA's Scheduling Procedures posted on BPA's OASIS.

3. EXHIBIT PROVISIONS

(a) **Scheduling Principles**

The procedures in this exhibit are intended to achieve the following principles:

(1) promote reliable and efficient system operations; and

(2) provide workable transmission scheduling provisions for the timely delivery of power.

(b) **Control Area Requirements**

(1) In order to schedule transmission for the movement of power, a Transmission Customer must designate an HCA to implement its transmission schedules. Subject to subsection (b)(2) below, the HCA may be the delivering Control Area, the receiving Control Area, or an intermediary Control Area.

(2) BPA shall be the HCA for any transaction involving either:

(A) generation within BPA's Control Area; or

(B) service to a load within BPA's Control Area.

(3) If BPA is the intermediary Control Area in a single transaction or set of transactions, the Transmission Customer may designate an HCA other than BPA. The Transmission Customer must inform BPA of its choice no later than the time of preschedule. BPA has no obligation to accept transmission schedules from any HCA that does not agree to abide by the scheduling requirements set forth in BPA's Transmission Scheduling Procedures posted on BPA's OASIS.

(4) If the Transmission Customer has designated an HCA for a single transmission schedule, the transmission schedule must remain with the HCA for the entire duration of the transmission schedule. In the event the Transmission Customer fails to identify a HCA for its next transmission schedule, BPA will assume that the designated HCA is the same entity as designated for the Transmission Customer's last transmission schedule.

(5) The Transmission Customer may submit interchange transmission schedules; however, the HCA shall confirm and then implement the interchange transmission schedules.

(6) Any Transmission Customer for whom BPA is the HCA must schedule transmission to, from, or within BPA's Control Area.

(c) **Coordinating Requirements**

(1) Scheduled hourly values are to be referenced by the "Hour Ending" time on the 24-hour clock (i.e., the schedule for 2-3 p.m. is referred as the "hour ending 15" or in other words "hour ending 1500").

(2) Unless otherwise agreed, all transmission schedules will be effectuated on an hourly basis using the standard 20-minute ramp period centered on the hour (i.e., beginning 10 minutes prior to the hour and ending 10 minutes after the hour).

(3) All schedules with BPA are to be stated in Pacific Time (PT) and are to begin with the Hour Ending 1.

(4) The Transmission Customer or its Scheduling Agent agrees to submit all hourly scheduled quantities in whole megawatthour amounts.

(d) **Prescheduling Requirements**
Prescheduling is the process of establishing hourly schedules.

(1) **Preschedule Submissions**

(A) The Transmission Customer or its Scheduling Agent agrees to submit Transmission Schedule(s) covering all transactions into, out of, or within BPA's Control Area.

(B) BPA may require the Transmission Customer or the Transmission Customer's Scheduling Agent to submit *estimated* preschedules prior to the final preschedule.

(C) The Transmission Customer or its Scheduling Agent agrees to submit a *final* hour*ly* preschedule for the next day or days consistent with the BPA's Transmission Scheduling Procedures as posted on BPA's OASIS.

(2) **Information Required to Be Included in Preschedule**
Any schedule submitted to BPA by the Transmission Customer or its Scheduling Agent must include, at a minimum, the following information:

(A) the HCA;

(B) the supplier (delivering party), receiver (Receiving Party), and wheeling entities involved in the transaction;

(C) the hourly MW amount of the transmission schedule;

(D) the starting and ending times for each transmission schedule;

(E) the Transmission Service being scheduled by product type (i.e. PTP or NT and firm or nonfirm) and subproduct type (i.e. hourly, daily, weekly, monthly, and/or annual);

(F) the Point of Interconnection/Delivery for the transaction;

(G) Transmission Agreement Contract Numbers and/or OASIS Reservation identification numbers as required by NERC; and

(H) all other pertinent information as required for transmission scheduling listed in BPA Transmission Scheduling Procedures posted on BPA's OASIS.

(e) **Real Time Changes**

(1) To the extent changes from the preschedule become necessary, the Transmission Customer or its Scheduling Agent must submit such requests to change the transmission schedule as specified in BPA's Transmission Scheduling Procedures posted on BPA's OASIS.

(2) Multihour changes from preschedule shall specify an "Hour Beginning" and an "Hour Ending" and shall never be stated as "until further notice."

(3) Upon a Transmission Customer's or its Scheduling Agent's request, BPA will consider mid-hour changes from preschedule under critical operating conditions such as loss of a resource or transmission path. The Transmission Customer or its Scheduling Agent and BPA must agree to the effective time, ramp duration, integrated, and revised net schedules for mid-hour changes. Mid-hour schedule changes shall not be made for economic or load shaping purposes. Such changes are subject to applicable charges.

(f) **Emergency Requirements**

(1) **Loss of Transmission Path**

(A) The path operator shall notify affected Transmission Customers, their Scheduling Agents and HCAs as rapidly as possible of the loss of a transmission path.

(B) The path operator will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify transmission schedules, as required, per the established effective time, and agree on integrated and revised net transmission schedules.

(2) **Loss of Generating Resource**
The Transmission Customer agrees to adhere to the following requirements for any resources that it operates, and agrees to ensure, through contractual arrangement, that any entity operating a resource on its behalf likewise agrees to the following:

(A) The operating entity (generating entity) will notify BPA and affected Transmission Customers, their Scheduling Agents, and HCAs as quickly as possible of the resource loss.

(B) The entity with Control Area responsibility will establish the effective time (midpoint of ramp) of schedule change.

(C) All parties to a transaction shall terminate or modify transmission schedules, as required, as of the established effective time, and agree on integrated and revised net schedules.

(3) **General Provisions Regarding Emergencies**
BPA and the Transmission Customer, its Scheduling Agent, and HCA agree to expedite communications to avoid accumulation of inadvertent powerflows or net transmission schedules which place a control burden on other Control Areas.

(g) **After-the-Fact Verification**

The Transmission Customer or its Scheduling Agent agrees to verify all transmission schedules and tie checks each week with a final verification at the end of each month consistent with the following principles:

(1) The Transmission Customer or its Scheduling Agent and BPA will check all scheduled transmission.

(2) The Transmission Customer or its Scheduling Agent and BPA will agree on the hourly transmission amounts and the transmission attributes of the transmission schedule (i.e. firm, nonfirm, hourly, daily, weekly, monthly, annual), transmission loss calculations, and transmission loss schedules (as appropriate).

(3) The Transmission Customer or its Scheduling Agent will assist BPA, as necessary, to reconcile all differences between actual and scheduled deliveries in a timely manner.

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AUTHENTICATED

EXHIBIT C
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 12

The OASIS Number is 756-P, the Assignment Reference Number (ARef) is: 1350339

1. TERM OF TRANSACTION

Start Date: 0000 hours on July 1, 2006.
Termination Date: 0000 hours on July 1, 2007.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1]	POR (Voltage)	POR Control Area	Maximum POR Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]	Scheduling Agent[2]
	John Day (500 kV)	BPA	See Sect. 3 Below	California Oregon Border (500 kV)	CAISO	See Sect. 3 Below		TransAlta Designated Agent
Total Transmission Demand			**See Sect. 3 Below**			**See Sect. 3 Below**		

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and/or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF RECEIPT AND POINTS OF DELIVERY

Point(s) of Receipt (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	**COB (500 kV)**	**(42 MW)**	**IS-04**

4. DESCRIPTION OF POINTS OF RECEIPT

John Day Substation

Location: the points in BPA's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

California Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB), where BPA shall make electric power available for the California Independent System Operator (CAISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $49,392, shall be paid to the Transmission Provider. For the second reservation fee, the Transmission Provider will bill the Transmission Customer 30 days prior to their due date. If the deferral or extension of the service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The reservation fee is based on the IS rate only and does not include either of the two Ancillary Services that the Transmission Customer is obligated to purchase from the Transmission Provider.

TRANSALTA ENERGY MARKETING (US), INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ TOM COYLE**	By: **/S/ BRIAN D ALTMAN**
Name: **Tom Coyle** *(Print/Type)*	Name: Brian D. Altman *(Print/Type)*
Title: **President**	Title: Transmission Account Executive
Date: **18 Oct/04**	Date: **4 Oct 04**

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Amendment No. 1
Contract No. 98TX-10172

AUTHENTICATED

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

TRANSALTA ENERGY MARKETING (US), INC. - TEMUS

This AMENDMENT to the Transmission Service Agreement, Contract Number 98TX-10172, (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and TransAlta Energy Marketing (US) (herein after referred to as "the Transmission Customer") The Transmission Customer and BPA are sometimes referred to individually as "Party", and collectively as "Parties" as the context suggests below.

This Amendment No. 1 (Amendment) to the Agreement between BPA and the Transmission Customer acknowledges the Parties' desire to extend the term of the Agreement to 2400 hours September 30, 2010. The Parties agree that all other terms and conditions of the Agreement remain the same. Article 3 of the Agreement is hereby amended to read as follows:

> "Service under this Service Agreement shall commence at 2400 hours on August 5, 1998. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on September 30, 2010; or (b) two years after the Transmission Customer provides written notice of termination pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied."

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

TRANSALTA ENERGY MARKETING (US), INC. - TEMUS

By /s/ DENISE E. HILL

Name DENISE E. HILL
(Print/Type)

Title MANAGER, PORTLAND OPERATIONS

Date JANUARY 20, 2000

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By /s/ KIPPEN R. MOXNESS
Transmission Account Executive

Name Kippen R. Moxness
(Print/Type)

Date JANUARY 19, 2000

(TM-TMC-W:\TMC\CT\TransAlta\10172AA!)

AUTHENTICATED

Exhibit C Table 5
STATEMENT OF SPECIFICATIONS FOR
LONG-TERM FIRM TRANSMISSION SERVICE

1. TERM OF TRANSACTION

Start Date: at hour ending 0100 hours on October 1, 2003.

Termination Date: at 2400 hours on September 30, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1/]	POI (Voltage)	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1/]	Scheduling Agent[2/]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LADWP	See Sect. 3 Below		TransAlta Designated Agent
Total Transmiss Demand			See Sect. 3 Below			See Sect. 3 Below		

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation 230/500 kV	NOB 1000 kV	10/01/03 - 9/30/06: 100 MW	IS-96

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation:

Location: the points in BPA's Big Eddy Substation where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses.

Voltage: 230/500 kV

Metering: quantities are to be scheduled

[1/] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2/] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

5. **POINTS OF DELIVERY**

Nevada/Oregon Border (NOB):

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where BPA shall make electric power available for the Transmission Customer.

Voltage: 1,000 kV

Metering: quantities are to be scheduled

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and it's affiliate (if they own transmission facilities)

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
none

8. **RESERVATION FEE:** Within thirty (30) days after the Transmission Customer signs this Exhibit A Table 5 to the Service Agreement, the first annual nonrefundable reservation fee of $ 127,400.00 shall be paid to BPA. For the second and subsequent reservation fees, BPA will bill the Transmission Customer thirty (30) days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS Rate only and does not include Ancillary Services.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ KIPPEN R. MOXNESS

Name: Kippen R. Moxness

Title: Transmission Account Executive

Date: January 30, 2001

TRANSALTA ENERGY MARKETING (US)

By: /S/ DENISE HILL

Name: 2/20/01 Denise Hill
(Print/Type)

Title: Mgr, Transmission

Date: 2/20/01

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Contract No. DE-MS79-89BP92273
12/05/89

GENERAL TRANSMISSION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

[Integration of Resources]

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This GENERAL TRANSMISSION AGREEMENT, executed December 11, 1989, by the UNITED STATES OF AMERICA (Government), Department of Energy (DOE), acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PORTLAND GENERAL ELECTRIC COMPANY (Company), a corporation of the State of Oregon,

W I T N E S S E T H :

WHEREAS Bonneville and the Company, on August 27, 1982, entered into Contract No. DE-MS79-81BP90425, (which as the same may be amended or replaced is hereinafter referred to as Power Sales Contract); and

WHEREAS Bonneville and the Company have entered into the following transmission agreements: Contract No. 14-03-001-13437 for the Priest Rapids Project; Contract No. 14-03-001-13773 for the Rocky Reach Project; Contract No. 14-03-28002 for the Wanapum Project; Contract No. 14-03-29139 for the Centralia Thermal Project; Contract No. 14-03-41848 for the Wells Project; Contract No. 81BP90167 for the Colstrip Project; and Contract No. DE-MS79-81BP90016 for the Beaver Project (which are hereinafter collectively referred to as the Prior Agreements); and

WHEREAS Bonneville and the Company desire to replace the Prior Agreements with this general transmission agreement; and

WHEREAS Bonneville and the Company have negotiated this agreement, the General Transfer Agreement, Contract No. DE-MS79-89BP92384, and a Letter Agreement, Contract No. DE-MS79-90BP92865, contemporaneously such that the Bonneville and the Company benefit from favorable terms in one agreement in exchange for concessions in the others; and

WHEREAS Bonneville and the Company are owners of certain AC Intertie facilities and have agreed to share the transmission capacity of the combined facilities through the terms and provisions of Contract No. DE-MS79-87BP92340 (Intertie Agreement); and

WHEREAS the Company has rights to transmission over the Montana Intertie pursuant to Contract No. DE-MS79-81BP90210 (Montana Intertie Agreement); and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Term of Agreement.

(a) This agreement shall be effective at 2400 hours on December 31, 1989 (Effective Date) subject to subsection 9(e) and shall continue in effect until 2400 hours on December 31, 2009.

(b) Upon expiration of this agreement, Bonneville will offer to extend transmission services provided hereunder, of the same quality as, and on terms and conditions consistent with, those being offered at that time to other customers similarly situated.

(c) If the Total Transmission Demand is reduced to zero pursuant to the terms and provisions of subsection 10(b), the Company may request termination of this agreement subject to satisfaction of all obligations accrued hereunder and completion of all notice periods specified in subsection 10(b) for the resources involved.

2. Termination of Prior Agreements. The Prior Agreements are hereby terminated as of the Effective Date hereof, but all obligations incurred thereunder are hereby preserved until satisfied.

3. Definition and Explanation of Terms.

(a) "AC Intertie." The alternating current (AC) transmission facilities, located in the State of Oregon, for transferring power and energy between the

Pacific Northwest and California, consisting of two 500 kV AC lines from John Day Substation to the California border and associated facilities.

(b) "Agency." The Agency authorized to approve Bonneville's transmission rates.

(c) "Electric Power" or "Power." Electric peaking capacity, expressed in kilowatts, or electric energy, expressed in kilowatthours, or both.

(d) "FCRTS" or "Federal Columbia River Transmission System." The transmission facilities of the Federal Columbia River Power System (FCRPS), which include all transmission facilities owned by the Government and operated by Bonneville, and other regional facilities over which Bonneville has obtained transmission rights.

(e) "Points of Delivery" or "POD." The point or points, named in the Transmission Parameters Exhibit, where Electric Power may be made available to the Company hereunder.

(f) "Points of Integration" or "POI."

(1) The point or points listed in the Transmission Parameters Exhibit, where Electric Power from the Company's Resources shall be integrated into the FCRTS hereunder; or

(2) the point or points mutually agreed upon by the parties hereto where Electric Power from other Resources may be made available to Bonneville for nonfirm transmission to the Company's Points of Delivery.
If requested, the Resources to be integrated at each Point of Integration shall be identified.

(g) "Resource."

(1) Any of the Company's generating or contractual resources listed in the Transmission Parameters Exhibit requiring firm transmission services on the FCRTS; and

(2) any resource within the Pacific Northwest region as defined in the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act) Section 3 (14), that is acquired from regional utilities for which nonfirm transmission service is requested and which is made available to Bonneville at mutually agreed upon Points of Integration on the FCRTS; and

(3) any resource within the Pacific Northwest region as defined in (2) above supplying backup power or station service to the Company's other resources, which requires nonfirm transmission and which is made available to Bonneville at the Company's Points of Integration on the FCRTS.

(h) "Southern Intertie." The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border, a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation, and one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

(i) "Southern Intertie Terminals." The John Day and Big Eddy Substation facilities which terminate the lines for transferring power and energy between the Pacific Northwest and the Pacific Southwest.

(j) "Total Power Integrated." For each hour, it is the sum of both firm and nonfirm Electric Power scheduled hereunder on such hour to Bonneville at all points on the FCRTS where Bonneville accepts such Electric Power from the Company for transmission hereunder to the Company's Points of Delivery.

(k) "Transmission Demand." The maximum firm transmission capacity which Bonneville shall be obligated to have available at each Point of Integration for the purpose of integrating Electric Power from a Resource specified in the Transmission Parameters Exhibit for the Company hereunder. The level of the Transmission Demand shall be based on the hourly peak capability of the

Company's Resource to be integrated hereunder at such Point of Integration. The sum of the Company's Transmission Demands (Total Transmission Demand) is specified in the Transmission Parameters Exhibit.

(l) "Use-of-Facilities Charge." The charges, if any, specified in the Transmission Parameters Exhibit, applicable to Points of Integration and Points of Delivery for the purpose of recovering the cost of identifiable facilities provided by Bonneville for the Company's use, provided payment for such use is not otherwise included in the charges pursuant to subsection 6(a).

(m) "Workday." For the purpose of power scheduling, it is a day which the parties hereto jointly observe as a regular workday.

4. Exhibits; Interpretations. The rights and obligations of the parties with respect to provisions hereunder shall be subject to and governed by this agreement, including Exhibits A through E (Exhibits) attached hereto and by this reference made a part of this agreement. The provisions of Section 38 of the General Wheeling Provisions [GWP Form-4R] require a minimum notification prior to a Rate Adjustment Date. If the rates are disapproved or conditions are placed on them by the Agency, Bonneville shall not be required to give minimum notice prior to resubmitting the rates to the Agency or implementing Agency approved rates. The headings used in this agreement are for convenient reference only, and shall not affect the interpretation of this agreement. The Company shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in the General Wheeling Provisions Exhibit.

5. Integration of Electric Power.

(a) During each hour of the term hereof, subject to the conditions stated herein, the Company shall make available or arrange to have made available to Bonneville, at the Points of Integration, the Total Power Integrated; and Bonneville shall, for each such hour, make an amount of Electric Power equal

to the Total Power Integrated available to the Company at the Points of Delivery, subject to the conditions in paragraphs (a)(1) through (a)(3) below.

(1) Bonneville may, but shall not be obligated to, integrate amounts of Electric Power on any hour which exceed the Total Transmission Demand.

(2) Bonneville may, but shall not be obligated to, integrate at a Point of Integration on any hour, amounts of Electric Power which exceed the Transmission Demand at such Point of Integration.

(3) Bonneville may, but shall not be obligated to, integrate Electric Power from Resources other than Resources listed in the Company's Transmission Parameters Exhibit, provided that the Points of Integration for such Electric Power have been mutually agreed upon; provided however any such integration of power, to the extent that the Total Transmission Demand is not exceeded, shall be provided in accordance with the Integration of Resources Transmission Rate Schedule; and provided further that Bonneville agrees not to refuse to provide and not to interrupt nonfirm transmission under this agreement for the delivery of the Company's purchases from Resources for displacement of its Resources solely for Bonneville to market electric energy to the Company. The Energy Transmission Rate Schedule shall not be applicable to integration of power from Resources to the extent such integration does not exceed the Total Transmission Demand.

(b) As between Bonneville and the Company, sharing the capability to deliver power and energy over the Southern Intertie is defined and limited by the terms and conditions of the Intertie Agreement. Nothing in this agreement, including integration by Bonneville of power and energy at Points of Delivery at the Southern Intertie Terminals, is intended to provide rights to use the Southern Intertie or to expand the rights defined in the Intertie

Agreement. Bonneville shall also accept or deliver Electric Power for delivery over the Montana Intertie as provided by the Montana Intertie Agreement. Nothing in this agreement shall provide for rights to use the Montana Intertie or expand the rights defined in the Montana Intertie Agreement.

(c) If, for any hour, the Company determines that it has Electric Power available for nonfirm transmission over the FCRTS, which would cause the Total Power Integrated to temporarily exceed the Total Transmission Demand, the Company may request nonfirm transmission service from Bonneville and Bonneville may provide transmission service for such excess Electric Power as a separately identified part of its schedule pursuant to Section 7. Charges for such transmission shall be applied in accordance with the Energy Transmission rate schedule, or its successor, attached hereto as part of Exhibit A.

(1) The option to schedule Electric Power as nonfirm transmission service shall not be used to avoid having a Total Transmission Demand which reasonably reflects Transmission Demand for each Resource and the noncoincidental sum of the peak demand for integrating firm energy which the Company places on Bonneville's system. Bonneville shall have the right to refuse to provide service on a nonfirm basis if it determines that the Transmission Demand at a Point of Integration should be increased or the Total Transmission Demand should be increased; provided that this sentence shall not apply if the Company has requested an increase in Transmission Demand, and Bonneville is unable to accommodate this request.

(2) Any transaction using the FCRTS which is exempt from transmission charges or loss assessment at the time of actual transmission, such as qualifying transactions under the Coordination Agreement (Contract No. 14-03-48221), and which is subsequently converted

to a sale to an entity other than Bonneville, shall be retroactively billed as nonfirm transmission service and shall be assessed losses unless such conversion is allowed or provided for under another agreement to which Bonneville is a party. Such qualifying transactions shall not be subject to paragraph (c)(1) above and (d) below.

(d) Except as provided in subsection 5(c) for nonfirm transmission, amounts of Electric Power integrated hereunder which exceed the Transmission Demand shall be billed under the ratchet provision of Section 6, or the Bonneville rate for transmission without prior agreement, should such a rate be developed and approved by the Agency in the future.

(e) To compensate Bonneville for losses incurred in providing services hereunder, the Company shall make available to Bonneville from the Company's system Points of Delivery unless otherwise mutually agreed between the parties, at the corresponding hour 168 hours later or at another hour mutually agreed upon, the amounts of Electric Power determined pursuant to the Calculation of Losses Exhibit (Returned Losses) for service performed pursuant to subsections (a) and (c) above.

(f) Bonneville shall, if requested by the Company and if it is within Bonneville's capability to do so without adversely affecting its other obligations, make replacement Electric Power available to the Company hereunder, without additional cost to the Company except as provided in this subsection, if Electric Power to be made available to Bonneville pursuant to subsection (a) above cannot be made available solely because of suspension or interruption of, or interference with, the operation of the FCRTS. The Company shall, at Bonneville's option:

(1) reimburse Bonneville for any cost or loss of revenue incurred in making such replacement Electric Power available;

(2) replace all or a portion of such replacement Electric Power with the Company's Electric Power at a time agreed upon by the parties prior to delivery; or

(3) reimburse and replace pursuant to paragraphs (1) and (2) above in amounts determined by Bonneville which in total are equivalent in value to the replacement Electric Power delivered to the Company pursuant to this subsection. The method to replace or reimburse shall be specified by Bonneville at the time of the Company's request for replacement Electric Power.

(g) The Company shall not use rights obtained under this agreement to provide transmission services for another entity.

6. Payment by the Company. As compensation for services provided hereunder, the Company shall pay Bonneville each month during the term hereof, amounts determined as provided in this Section and in accordance with the Transmission Parameters Exhibit and the Transmission Rate Schedules and General Transmission Rate Schedule Provisions Exhibit. Any ratchet demand that may occur as determined by Bonneville pursuant to the Transmission Rate Schedules and General Transmission Rate Schedule Provisions, does not constitute an increase in any Transmission Demand approved by Bonneville and any continued service at such level will depend on the availability of facilities as determined by Bonneville. Any changes in Transmission Demands must be requested in accordance with Section 10.

(a) For integration of Electric Power up to the Total Transmission Demand pursuant to subsection 5(a), the Company shall pay Bonneville in accordance with the IR rate schedule, or its successor rate, and in accordance with the Use-of-Facilities methodology in Exhibit C.

(b) For nonfirm transmission of Electric Power pursuant to subsection 5(c), the Company shall pay Bonneville in accordance with the Energy Transmission Rate Schedule, or its successor.

7. Power Scheduling. The Company shall submit or arrange to have submitted the schedule for the Total Power Integrated to Bonneville by 1200 hours (Pacific Time) of each Workday:

(a) for resources requiring transmission herein to which the Company has generation control:

(1) a retroactive report of the Electric Power supplied to Bonneville for each hour of the previous day or days: and

(2) at Bonneville's request, estimated amounts of Electric Power as specified in paragraph (1) above for each hour of the following day or days;

(b) for resources requiring transmission herein to which the Company does not have generation control:

(1) at Bonneville's request, a schedule in advance of Electric Power to be supplied to Bonneville for each hour of the following day or days; and

(2) if the resource is within Bonneville's control area, a retroactive report of the Electric Power supplied by each resource as made available to Bonneville for each hour of the previous day or days.

(c) A retroactive report of the hourly amounts of Electric Power which the Company made available to Bonneville for nonfirm transmission pursuant to subsection 5(c); provided however, that if requested by Bonneville, the Company shall submit estimated amounts of Electric Power to be made available for nonfirm transmission and indicate the Point of Integration where such Electric Power shall be made available; and

(d) separate schedules of the hourly amounts of Electric Power to be made available pursuant to subsection 5(e) for losses for each hour of the following day or days.

8. Reactive Power. It is the intent of the parties hereto that the voltage levels at the Points of Integration and the Points of Delivery be controlled in accordance with prudent utility operating practice. The parties hereto shall jointly plan and operate their systems so as not to place an undue burden on the other party to supply or absorb reactive power accompanying or resulting from interconnections of the systems of the parties and from the integration of Electric Power or deliveries hereunder.

9. Revision of Exhibits.

(a) The rate schedules included in the Transmission Rate Schedules and General Transmission Rate Schedule Provisions Exhibit shall be replaced by successor rate schedules in accordance with the provisions of subsection 7(i) of the Pacific Northwest Power Act and Agency rules. The unit rate or rates in such successor rate schedules shall be a non-mileage based rate which shall only reflect the distances between POI's and POD's if a short distance discount factor has been agreed upon by the parties.

(b) The initial rate schedules to be attached in the Transmission Rate Schedules and General Transmission Rate Schedule Provisions Exhibit have been confirmed and approved by the Agency on an interim basis. If the final rate schedules which are approved by the Agency are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated general transmission rate schedule provisions shall be attached hereto and made a part of this agreement effective as of the date specified in the Agency's approval.

(c) Bonneville shall annually review the Calculation of Losses Exhibit and shall revise such exhibit as appropriate to incorporate values which represent then current FCRTS operating conditions or to incorporate any value, used in such exhibit to calculate the losses, which has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with the Company. Bonneville shall prepare a new Losses Exhibit incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that other Use-of-Facilities Charges specified herein or Parameters used in calculating any charges specified in this agreement must be changed pursuant to Sections 19 or 38 of the General Wheeling Provisions Exhibit, it shall prepare a new Transmission Parameters Exhibit or other affected exhibit incorporating such revised charges and factors. Such new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. Use-of-Facilities Charges may be increased to accommodate the addition of new facilities associated with Points of Integration and Delivery only if such facilities are reasonably necessary to continue providing service, pursuant to this agreement, of the same quality as that provided at the beginning of the term hereof or as of the effective date of additional Points of Integration and Delivery, as appropriate.

(e) Part C of the Transmission Parameters Exhibit (Exhibit C) contains the methodologies for calculating the Joint Use-of-Facilities Charges and the Sole Use-of-Facilities Charges. Bonneville agrees, for the term of this agreement, to seek continuance of such methodology by advocating a rate schedule or schedules which accommodate the methodology set forth in Part C to the Agency or its successor, or a court of competent jurisdiction, and, except

as provided below, to never propose a change in such methodology, applicable to this agreement, in any rate procedure conducted under Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 USC Section 839e(i). In the event Bonneville is required by the Agency or a court of competent jurisdiction, to change such methodology, the Company and Bonneville may agree upon another mutually acceptable methodology and seek appropriate regulatory approval, if necessary. If Bonneville and the Company fail to agree on a methodology, or if regulatory approval is not granted, then the Company shall have the right to terminate this agreement upon notice of not less than 1 year and not more than 5 years, provided however, that upon termination Bonneville shall offer to extend resources integration transmission services including services to the Southern Intertie Terminals, of the same quality as, and on terms and conditions consistent with those being offered at that time to other customers similarly situated.

10. Addition or Deletion of Points of Integration and Points of Delivery and Changes in Transmission Demands.

(a) Points of Integration and Points of Delivery may be added and Transmission Demands may be increased, subject to mutual agreement of the parties and to Bonneville's determination of available transmission capacity, upon 3 months' prior written notice to Bonneville, but no more frequently than once in any 12-month period for any individual point or Transmission Demand. Such changes shall be effective for the remaining term of this agreement unless otherwise indicated in the appropriate exhibits hereto, or changed pursuant to the provisions hereof.

(b) Points of Integration and Points of Delivery may be deleted and Transmission Demands may be reduced subject to the provisions of paragraphs (b)(1) through (b)(5) below.

(1) Transmission Demands for individual Points of Integration may be reduced no more frequently than once in any 12-month period for any Point of Integration, subject to the provisions of paragraph (b)(4) below and the notice requirements of paragraph (b)(5) below and only:

(A) to the extent that, pursuant to the provisions of agreements between the Company and the owner of a Resource designated in the Transmission Parameters Exhibit as being integrated at such Point of Integration, the Resource owner withdraws all or a portion of the Company's share of the Resource output; or

(B) to the extent that the Company assigns all or a portion of its share of the Resource output; or

(C) to the extent of a permanent partial or total reduction in the Company's entitlement to a share of the capability of the Resource; or

(D) to the extent of the destruction, abandonment, or sale of a Resource integrated at such Point of Integration; or

(E) to the extent of the discontinuation of operation of a Resource under a final order of a public official having authority to issue such order.

(2) A Point of Integration may be deleted, upon 3 months' prior written notice to Bonneville, subject to paragraph (b)(4) below, but only after its Transmission Demand has been reduced to zero pursuant to paragraph (b)(1) above.

(3) A Point of Delivery may be deleted, subject to mutual agreement of the parties hereto and to paragraph (b)(4) below, upon 3 months' prior written notice to Bonneville.

(4) A reduction of a Transmission Demand or the deletion of a Point of Integration or a Point of Delivery shall not decrease the Company's obligation to pay, for the duration of this agreement, the Use-of-Facility Charges specified in the Transmission Parameters Exhibit, except to the extent that another customer of Bonneville obligates itself to make such payments to Bonneville for the remainder of the duration of this agreement; provided, however, that upon mutual agreement, the parties may negotiate a termination charge in lieu of continued periodic payment of Use-of-Facility Charges for the duration of this agreement.

(5) The Company shall provide Bonneville 3 years' written notice of any decrease in Transmission Demand, except as follows:

(A) the Company shall provide 3 months' written notice of a decrease in Transmission Demand if there is an equal increase in Transmission Demand by another customer at the same Point of Integration resulting from the sale or assignment of the Resource and involving no loss of revenue to Bonneville; or

(B) the Company shall provide written notice as soon as possible if such decrease is due to involuntary total or partial loss of a Resource, or discontinuation of operation of a Resource under a final order of a public official having authority to issue such order, or if the Company's right to receive Electric Power is reduced or eliminated according to the terms of an agreement between the Company and another entity for such Electric Power.

(c) When changes are made pursuant to this Section, Bonneville shall incorporate such changes in a new Transmission Parameters Exhibit as soon as practicable.

11. Ratification of Interim Agreement. Bonneville billed and the Company paid for transmission services for the Boardman Project pursuant to the FPT Transmission Rate Schedule for the following periods: From 2400 hours August 3, 1980 to 2400 hours June 27, 1982; and from 2400 hours January 31, 1984 to 2400 hours August 18, 1984.

Bonneville billed and the Company paid for transmission services for the Boardman Project pursuant to the IR Transmission Rate Schedule for the following periods; from 2400 hours on June 27, 1982 to 2400 hours on

January 31, 1984; and from 2400 hours on August 18, 1984 to the Effective Date of this agreement.

IN WITNESS WHEREOF, the parties hereto have executed this agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Walter E. Pollard
Assistant Administrator
for Power Sales

James J. Jura

PORTLAND GENERAL ELECTRIC COMPANY

By E. Kay Stepp

Title President

Date December 11, 1989

(VS6-PMT-3188e)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Transmission Parameters

A. Points of Integration, Transmission Demands, and Resources.

Point of Integration (Voltage)	Transmission Demand	Resource(s) to be Integrated
Midway Substation (230 kV)	131 MW	Priest Rapids Development 1/
Rocky Reach Switching Station (230 kV)	143 MW	Rocky Reach Project 1/
Vantage Substation (230 kV)	161 MW	Wanapum Development 1/
Douglas Switch Yard (230 kV)	169 MW	Wells Project 1/
Garrison Substation (500 kV)	270 MW	Colstrip Project 2/
C.W. Paul Substation (500 kV)	34 MW	Centralia Thermal Project
Allston Substation 3/ (230 kV)	531 MW	Beaver Combined Cycle Plant
Slatt Substation (500 kV)	349 MW 4/	Boardman Project
Total Transmission Demand	1788 MW	

1/ BPA will integrate from these POI's to the POD's listed in this exhibit Electric Power the Company obtains from other participants' shares of these Resources up to the Company's full Transmission Demand at each of these POI's.

2/ BPA will integrate from the Garrison POI to the POD's listed in this exhibit additional Electric Power belonging to the Company other than the Company's shares of the Colstrip Project which the Company makes available to Bonneville at the POI; provided, however, (i) the total Power made available at the Garrison POI shall not exceed the Transmission Demand for that POI; and (ii) the resource is a resource within the Pacific Northwest region as defined in the Pacific Northwest Electric Power Planning Conservation Act (Pacific Northwest Act) Section 3(14), and was in operation on May 17, 1988, or is from shares of Colstrip 1, 2, 3, and 4 other than the Company's shares. This provision does not increase nor decrease any rights that the Company has pursuant to Contract No. DE-MS79-81BP90210 (Montana Intertie Agreement), nor does this contract take precedence over other firm transmission contracts between Bonneville and other utilities.

3/ Beaver Combined Cycle Project (Beaver) integration involves a short distance discount. The POD's served by Beaver are all within 75 circuit miles of Beaver. The demand portion of the transmission charge for Beaver pursuant to the IR Rate Schedule Short Distance Discount is determined from following formula:
(.2 + [(.8/75) x distance]) (IR Rate per kW of transmission demand) =
Monthly charge per kW transmission demand
Applying power flow J8801CY87 dated 7/22/87, which is based on the normal operating situation with Trojan operating and Beaver idle, the Short Distance Discount is as follows:

POD	Demand (MW)	(Circuit Miles)	Factor	Charge $/kW	Compensation Charge $/kW
Keeler	270.0	42.4	0.652	0.170	0.086
Rivergate	150.0	50.7	0.743	0.193	0.055
Pearl	111.0	60.7	0.847	0.220	0.046
Total Demand	531.0				0.187/kW

4/ The Company's share of the Boardman Project totals 424 MW. The Company entered into a Long Term Power Sales Agreement with San Diego Gas & Electric Company (SDG&E) for 75 MW of the Company's share of the Boardman Project. Transmission services for this transaction are covered under Contract No. DE-MS79-86BP92260 which expires at 2400 hours on December 31, 2013. BPA will integrate from this POI to the POD's listed in this exhibit, Electric Power the Company obtains from other participants' shares of the Resource up to the Company's full Transmission Demand at the POI.

B. Points of Delivery and Use-of-Facilities Charges.

Points of Delivery	Use-of-Facilities Charges 1/
Bethel Substation (230 kV)	0
Big Eddy Substation (230 kV) 2/ (Southern Intertie)	0
D. R. Keeler Substation (230 kV)	0
John Day Substation (500 kV) 2/ (Southern Intertie)	0
McLoughlin Substation (230 kV)	0
Pearl Substation (230 kV)	0
Rivergate Substation (230 kV)	0
Trojan Substation (230 kV) 3/	0
Points of Delivery for Station Service Only Unless Otherwise Noted 4/	
Rocky Reach Switching Station (230 kV)	0
Midway Substation (230 kV)	0
Vantage Substation (230 kV)	0
C.W. Paul Substation (500 kV)	0
Allston Substation (230 kV)	0
Slatt Substation (500 kV) 5/	6/
Garrison Substation (500 kV)	0

1/ There are no charges as of the Effective Date of this exhibit. Any revisions to these original zero charges shall be in accordance with subsection 9(d).

2/ Transmission of Electric Power over the Southern Intertie shall be in accordance with the terms and conditions of the Intertie Agreement, Contract No. DE-MS79-87BP92340. If Bonneville establishes other AC Intertie Points of Delivery and upon the Company's request, Bonneville may add them here according to Company's rights under the Intertie Agreement.

3/ Limited to deliveries when Trojan Generating Plant is not in operation.

4/ Upon Bonneville's request, the Company shall provide evidence of the obligation to provide station service and the amounts and conditions of such obligation.

5/ Bonneville shall integrate power pursuant to this agreement from a Point of Integration under this agreement to Boardman for the Company to the extent of obligations to replace the power of Pacific Northwest Generating Company and Idaho Power Company (or their assignees) when Boardman is displaced. Assignees shall mean any utility whose rights to the power have been assigned under a firm contract for a period of 12 months or more, and the assignee has the means of receiving the power. The Company shall provide evidence of this obligation at Bonneville's request.

6/ UFT Charges covered under a separate transmission agreement Contract No. DE-MS79-84BP91673.

C. Use-of-Facilities Methodology and Charges.

1. Methodology for Joint Use-of-Facilities Charges. 1/

$$\text{Unit Charge} = \frac{(\text{Investment})(\text{Annual Cost Ratio})\ 2/ + \text{Annual Operation and Maintenance}\ 3/}{\text{Noncoincidental Peak Demand}} = \$/\text{kW-yr}$$

$$\text{Monthly Charge} = \frac{(\$/\text{kW-yr})(\text{Trans. Demand})}{12\ \text{months}} = \$/\text{kW-mo.}$$

2. Methodology for Sole Use-of-Facilities Charges. 1/

$$\text{Unit Charge} = (\text{Investment})(\text{Annual Cost Ratio})\ 2/ + \text{Annual Operation and Maintenance}\ 3/ = \$/\text{yr.}$$

$$\text{Monthly Charge} = \frac{(\$/\text{yr})}{12\ \text{months}} = \$/\text{mo.}$$

1/ The methodology for Joint Use-of-Facilities Charges and Sole Use-of-Facilities Charges is an application of the UFT-83 rate schedule.

2/ Annual Cost Ratio from the most recent "Annual Financial Requirements for BPA Transmission System", as a percentage of plant investment without O&M.

3/ Annual Operation & Maintenance from the most recent "Actual O&M Costs and Service Lives for Main Grid Substation Components and Transmission Lines".

D. Description of Points of Integration and Points of Delivery.

These are definitions only. Designations of these points as either Points of Integration or Points of Delivery are in Part A or Part B of this Exhibit.

1. JOHN DAY SUBSTATION:

Location: the points in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV.

2. BIG EDDY SUBSTATION:

Location: the points in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus;

Voltage: 230 kV.

3. GARRISON SUBSTATION:

Location: the points in the Government's Garrison Substation where the line terminals of the Garrison-Townsend lines are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: in the Government's Garrison Substation, in the 500 kV circuits over which such Electric Power is made available to Bonneville.

4. PEARL SUBSTATION:

Location: the point in the Government's Pearl Substation where the 230 kV facilities of the parties hereto are connected;

Voltage: 230 kV;

Metering: in the Government's Pearl Substation, in the 230 kV circuit over which such Electric Power is delivered.

5. ROCKY REACH SWITCHING STATION:

Location: the point in Chelan County PUD's (PUD) switching station where the 230 kV facilities of PUD and the Government are connected;

Voltage: 230 kV.

6. DOUGLAS SWITCH YARD:

Location: the point in the Douglas County PUD's (Douglas) Douglas Switch yard where the 500 kV facilities of the Government and Douglas are connected;

Voltage: 500 kV.

7. MIDWAY SUBSTATION:

Location: the points in the Government's Midway Substation where the 230 kV facilities of the Government and Grant County PUD are connected;

Voltage: 230 kV.

8. VANTAGE SUBSTATION:

Location: the points in the Government's Vantage Substation where the 230 kV facilities of the Government and Grant County PUD are connected;

Voltage: 230 kV;

Metering: in the Government's Vantage Substation, in the 230 kV circuits over which such Electric Power flows.

9. MCLOUGHLIN SUBSTATION:

Location: the point in the Government's McLoughlin Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Government's McLoughlin Substation, in the 230 kV circuit over which such Electric Power flows.

10. RIVERGATE SUBSTATION:

Location: the point adjacent to the Company's Rivergate Substation on structure 8/2 of the Government's Ross-Rivergate 230 kV line where the facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Company's Rivergate Substation, in the 230 kV circuit over which such Electric Power flows;

Exception: there shall be no adjustment for losses between the point of delivery and the point of metering.

11. TROJAN SWITCHING STATION:

Location: the points in the Company's Trojan Switching Station where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Company's Trojan Switching Station, in the 230 kV circuits over which such Electric Power flows.

12. BETHEL SUBSTATION:

Location: the point in the Company's Bethel Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Company's Bethel Substation, in the 230 kV circuit over which such Electric Power flows.

13. C. W. PAUL SUBSTATION:

Location: the points in the Government's C. W. Paul Substation where the 500 kV facilities of the Government and the Company are connected;

Voltage: 500 kV.

14. SLATT SUBSTATION:

Location: the point in the Government's Slatt Substation where the 500 kV facilities of the Government and the Company are connected;

Voltage: 500 kV;

Metering: in the Government's Slatt Substation, in the 500 kV circuit over which such Electric Power flows.

15. ALLSTON SUBSTATION:

Location: the point in the Government's Allston Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Government's Allston Substation, in the 230 kV circuit over which such Electric Power flows.

16. D.R. KEELER SUBSTATION

Location: the point in the Government's D.R. Keeler Substation where the 230 kV facilities of the Government and the Company are connected;

Voltage: 230 kV;

Metering: in the Government's D.R. Keeler Substation, in the 230 kV circuit over which such Electric Power flows.

Losses

A. Losses Resulting From Transmission Pursuant to the Integration of Resources (IR) Rate Schedule.

Loss Factor

1.6%

B. Losses Resulting From Nonfirm Transmission Pursuant to the Energy Transmission (ET) Rate Schedule.

Loss Factor

1.6%

Other Transmission Agreements Between the Parties

Contract Number	Point of Interconnection	Point(s) of Delivery	Resource	Expiration Date
DE-MS79-86BP92260	Slatt Substation	John Day Substation	Boardman Project	12/31/2013
DE-MS79-85BP91882	Ione Substation	McLoughlin Substation	Kinzua Cogeneration Project	3/18/2005
DE-MS79-85BP92187	Satsop Substation	Keeler Substation	WNP 3	1/
14-03-47311	Various project interconnection points	As shown in Exhibit C to the contract	Canadian Entitlement Exchange Agreement	2/
14-03-47451 (Rocky Reach) 14-03-47453 (Wells) 14-03-47454 (Priest Rapids) 14-03-47455 (Wanapum)	Various project interconnection points	As shown in Exhibit C to the respective contracts	Canadian Entitlement Allocation Agreement	3/31/2003

1/ See WNP 3 Settlement Exchange Agreement, Section 1 (i), Definition and Explanation of Terms, "Exchange Termination Date"

2/ Later of 3/31/2003 or the date all bonds are paid.

(VS6-PMT-3188e)

Contract No. DE-MS79-87BP92340

INTERTIE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

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Exhibit A Sharing of Costs for Reliability Improvements and other Projects

Exhibit B Sharing of Costs for Plan-of-Service in Joint AC Intertie

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Exhibit F Calculation of Charges for Access to Southern Oregon Substation

Exhibit G Calculation of DC Intertie Losses

- -

This INTERTIE AGREEMENT, executed July 29, 1988, by the BONNEVILLE POWER ADMINISTRATION (Bonneville) and PORTLAND GENERAL ELECTRIC COMPANY (Portland), a corporation organized and existing under the laws of the State of Oregon.

W I T N E S S E T H :

WHEREAS Bonneville and Portland are owners of facilities that comprise the existing Joint AC Intertie; and

WHEREAS Bonneville and Portland are parties to Contract No. 14-03-55063 (Intertie Operations Agreement), and to Contract No. DE-MS79-84BP91883 (Intertie Settlement Agreement), which provided rights and responsibilities of

the parties regarding the Joint AC Intertie and which shall expire on December 15, 1988, unless extended or replaced; and

WHEREAS Bonneville and Portland desire to replace the Intertie Operations Agreement and Intertie Settlement Agreement with this Intertie Agreement; and

WHEREAS Bonneville and Portland desire to jointly operate their AC Intertie facilities as a single system in order to realize the full benefits of the combined facilities and to permit the ongoing use of the facilities for delivery and receipt of power and energy as described in this Agreement.

WHEREAS Bonneville, Portland, Pacific Power & Light Company (Pacific), and the Bureau of Reclamation entered into Contract No. 14-03-59840 (Malin Construction and Operations Agreement), Bonneville and Portland entered into Contract No. 14-03-29225 (Malin Construction Trust Agreement), and Contract No. 14-03-63627 (Malin Operation and Maintenance Trust Agreement) that include terms and provisions for facilities in the Joint AC Intertie in the Malin Substation; and

WHEREAS Bonneville and Portland entered into Contract No. 14-03-56747 (Grizzly Trust Agreement), Contract No. DE-MS79-86BP92277 (Grizzly Construction Trust Agreement), and Contract No. 14-03-73941 (Grizzly Operation and Maintenance Trust Agreement) that include terms and provision for facilities in the Joint AC Intertie at the Grizzly Substation; and

WHEREAS Bonneville and Pacific entered into Contract No. DE-MS79-86BP92299 (Pacific Intertie Agreement) that, among other things, gives Bonneville certain rights to establish a Plan-of-Service for the upgrade of the Northwest AC Intertie, and to construct and interconnect such intertie with Pacific's facilities; and

WHEREAS the California-Oregon Transmission Project (COTP) in California may be constructed and, if it is, Bonneville may desire to upgrade the Northwest AC Intertie to meet the expected increase in capacity, in which event Portland may desire to upgrade Portland's facilities in the Joint AC Intertie; and

WHEREAS Bonneville and Portland may, in the future, desire to further upgrade the facilities of the AC Intertie such that the Rated Transfer Capability of the AC Intertie is increased beyond the Transfer Capability of the COTP; and

WHEREAS Portland desires continuing ability to schedule power and energy for delivery to Pacific Southwest utilities at the Southern Oregon Substation; and

WHEREAS Bonneville and Portland agree to provide for the resolution of other agreements including a General Transfer Agreement, an Integration of Resources (IR) Agreement, and an exchange of a share of Portland's AC Rated Transfer Capability for an equal share of Bonneville's DC Rated Transfer Capability; and

WHEREAS Bonneville and Portland desire to resolve other outstanding issues regarding use of each other's system; and

WHEREAS nothing in this Intertie Agreement is intended to be determinative of transmission or ownership rights of utilities not party to this Agreement;

NOW, THEREFORE, in order to realize the full benefits from the facilities individually and jointly owned by the parties, to provide for the continuing use of those facilities, and to provide for planning, designing, operating, modifying, constructing, maintaining, and upgrading the individually and jointly owned facilities, known as the Joint AC Intertie, the parties hereto agree to the following:

1. Termination of Prior Agreements. The Intertie Operations Agreement and Intertie Settlement Agreement are hereby terminated on the Effective Date of this Agreement, but all obligations accrued thereunder are hereby preserved until satisfied.

2. Term of Agreement.

(a) With the exception of the provisions for operating and scheduling, which shall continue for 30 days from the Effective Date, this Agreement shall be effective on the date of execution (Effective Date) and shall continue in effect so long as the facilities of the Joint AC Intertie are in existence and operable.

(b) Should this Agreement terminate earlier than specified in subsection 2(a) for any reason except material breach of contract by either party, and the parties fail to agree to a replacement agreement, the parties agree to operate their jointly owned and separately owned facilities in such a manner to permit the continued use of the facilities for delivery and receipt of power and energy as described in this Agreement. Other than as excepted above, the parties intend this obligation to survive such earlier termination.

(c) Bonneville agrees not to participate in any renegotiation of provisions in the Pacific Intertie Agreement between Pacific and Bonneville effecting: (1) the ownership, operation, maintenance, or modification of the Joint AC Intertie; (2) the Rated Transfer Capability of the Northwest AC Intertie; or (3) Portland's right to make deliveries at Southern Oregon Substation as provided in subsection 8(c) of this Agreement, unless Portland is allowed to participate in the negotiations. In addition, Portland agrees not to participate in any negotiations with Pacific effecting: (1) ownership, operation, maintenance, or modification of the Northwest AC Intertie; or (2) the Rated Transfer Capability of the Northwest AC Intertie, unless Bonneville is allowed to participate in the negotiations.

(d) Bonneville and Portland agree to apply their best efforts to retain rights to deliver power and energy through Southern Oregon Substation.

3. Exhibits. Exhibits A through F are incorporated as part of this Agreement.

4. Definitions.

(a) COTP. The 500 kV transmission line proposed by the California-Oregon Transmission Project, or a successor line, which will operate in parallel with the existing 500 kV AC Intertie in California and that would increase the Rated Transfer Capability of the Northwest AC Intertie beyond the present capability of 3200 MW to as much as 4800 MW.

(b) DC Intertie. The DC Intertie consists of the Celilo converter station and the direct current line extending from the Celilo converter station to the Nevada-Oregon border, which are solely owned by Bonneville and which presently have a Rated Transfer Capability of approximately 2000 MW.

(c) DC Terminal Expansion. The planned increase in DC Intertie Rated Transfer Capability resulting from modifications to the Celilo and Sylmar Substations and the addition of new equipment to existing transmission facilities for the support of the DC Intertie. The planned Rated Transfer Capability of the Terminal Expansion is approximately 1100 MW, for a total DC Intertie Rated Transfer Capability of approximately 3100 MW.

(d) FCRTS or Federal Columbia River Transmission System. The transmission facilities of the Federal Columbia River Power System that include all transmission facilities owned and operated by Bonneville, and other regional facilities for which Bonneville has obtained transmission rights.

(e) Joint AC Intertie. For purposes of this Intertie Agreement, the Joint AC Intertie consists of alternating current (AC) transmission facilities, located in the State of Oregon, for transferring power and energy between the Pacific Northwest and California as follows: two 500 kV transmission lines extending from the John Day Substation to the Malin Substation, portions of John Day, Grizzly, and Malin Substations and the Bakeoven, Sand Springs, Fort Rock, and Sycan Compensation Stations. Consistent with the procedure specified in subsection 9(a), any modifications, additions, improvements, or other alterations to facilities in the Joint AC Intertie shall also become part of the Joint AC Intertie.

(f) Joint Intertie Scheduling Office. The group of Bonneville, Portland, and Pacific schedulers, which is presently located at Bonneville's Dittmer Control Center in Vancouver, Washington, and whose representatives are appointed from time-to-time to schedule energy over the Northwest AC Intertie.

(g) Northwest AC Intertie. The Northwest AC Intertie consists of those facilities in the Joint AC Intertie; and a portion of the Buckley-Summer Lake transmission line, Bonneville's rights in the 500 kV Summer Lake-Malin transmission line, and, should Bonneville require, the use of the 500 kV Meridian-Malin transmission line, the Southern Oregon Substation, and Bonneville's ownership of or rights to use the planned 500 kV Alvey-Meridian transmission line. Any modifications, additions, improvements, or other alterations to facilities in the Northwest AC Intertie shall also become part of the Northwest AC Intertie.

(h) Operational Transfer Capability. Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the parties, and operational limitations as a result of among other things line or equipment outages, stability limits, or loopflow.

(i) Plan-of-Service. The project plans developed to realize an increase in the Rated Transfer Capability of the Northwest AC Intertie from 3200 MW up to approximately 4800 MW, which project plans shall include but are not necessarily limited to plans, schedules, costs, and facility and equipment requirements.

(j) Prudent Utility Practice. At any particular time, the generally accepted practices, methods, and acts in the electrical utility industry existing prior to the subject action or the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(k) Rated Transfer Capability. The capability of a transmission line or system to transfer power in a reliable manner as determined in accordance with Prudent Utility Practice.

(l) Southern Oregon Substation. The proposed substation where the transmission line that interconnects with the COTP connects with the Northwest and Joint AC Interties in the Pacific Northwest.

(m) Unused Operational Transfer Capability. Operational Transfer Capability not being used during a given hour for a party's own schedules.

5. Ownership.

(a) Facilities in the Joint AC Intertie. Ownership of existing facilities is as follows:

(1) Bonneville has constructed and owns two 500 kV AC circuits from its John Day Substation to the Grizzly Substation, including two 500 kV terminal positions in said John Day Substation, and one 500 kV AC circuit from the Grizzly Substation to the Malin Substation (Grizzly-Malin No. 1

line). Bonneville also has constructed and owns the Bakeoven, and its Sand Springs, Fort Rock, and Sycan Compensation Stations.

(2) Portland has constructed and owns one 500 kV AC circuit from the Grizzly Substation to the Malin Substation (Grizzly-Malin No. 2 line). Portland also has constructed and owns its Sand Springs, Fort Rock, and Sycan Compensation Stations.

(3) Ownership of all facilities at the Grizzly Substation is as defined in the Grizzly Trust Agreement and the Grizzly Construction Trust Agreement.

(4) Ownership of all facilities at the Malin Substation is as defined in the Malin Construction and Operation Agreement and the Malin Construction Trust Agreement.

(b) By this Agreement, neither Bonneville nor Portland transfers to the other party ownership of existing or future facilities. While the provisions of section 8 provide Bonneville and Portland with scheduling rights based on the Rated Transfer Capability of the Northwest AC Intertie, there is no intention to transfer from one party to the other party any ownership in such facilities beyond those facilities presently owned by that party.

6. Operation of Northwest AC Intertie.

(a) Single System Operation. Bonneville and Portland, as between each other, hereby agree to operate their respective jointly owned and separately owned Northwest and Joint AC Intertie facilities as a single system so as to maximize, consistent with Prudent Utility Practice, the Rated and Operational Transfer Capability of the combined facilities.

(b) Committees.

(1) Management Committee. Bonneville and Portland shall form a Management Committee, consisting of one senior executive representative and an alternate from each organization possessing authority to commit their respective organization. The Management Committee shall oversee implementation of all provisions of this Agreement; designate representatives to and oversee the work of the Operations and Scheduling Committee and Engineering Committee; and resolve any disputes. Decisions of the Management Committee shall be by unanimous consent.

(2) Operation and Scheduling Committee. Among the duties of the Operation and Scheduling Committee are developing principles to guide the decisionmaking of the Operator and Joint Scheduling Office, and when the need arises to review the operation, maintenance, and scheduling of the Joint AC Intertie for consistency with the principles. The Management Committee may assign other duties to the Operation and Scheduling Committee where appropriate.

(3) Engineering Committee. Among the duties of the Engineering Committee are reviewing the plans for capital investments to the Joint AC Intertie. The Management Committee may assign other duties to the Engineering Committee where appropriate.

(c) Operator. Bonneville shall be the operator for the Northwest AC Intertie. As such, Bonneville shall be responsible for the dispatch of the Northwest AC Intertie in accordance with Prudent Utility Practice and the principles for operation developed by the Operation and Scheduling Committee, established pursuant to paragraph 6(b)(2). The duties of the operator include, but are not limited to, determining: (1) the Operational Transfer

Capability of the Northwest AC Intertie; (2) emergency outages; and (3) switching orders. In making such determination, Bonneville shall give fair consideration to Portland's interests in such matters, consistent with Prudent Utility Practice, to the extent those interests have been expressed to Bonneville in writing.

(d) Remedial Actions. Bonneville and Portland shall jointly develop through the Engineering Committee a plan for remedial actions, including generator dropping, required to support the Rated Transfer Capability of the Northwest AC Intertie. Each party shall provide, and be financially responsible for or make arrangements for, generator dropping or other remedial actions required to achieve the provisions of the plan. Each party's responsibility for such remedial actions, which may include generator dropping, shall be determined by dividing the party's share of Rated Transfer Capability in the Northwest AC Intertie by the total Rated Transfer Capability of the Northwest AC Intertie.

7. Shares of Rated Transfer Capability.

(a) Rated Transfer Capability at or below 3200 Megawatts (MW). During such time that the Rated Transfer Capability of the Northwest AC Intertie is less than or equal to 3200 MW, Portland's share of Rated Transfer Capability shall be equal to 25 percent of the Rated Transfer Capability of the Northwest AC Intertie. As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability of the Northwest AC Intertie shall be equal to 75 percent of the Rated Transfer Capability of the Northwest AC Intertie.

(b) Rated Transfer Capability greater than 3200 MW but not more than 4800 MW. During such time that the Rated Transfer Capability of the Northwest AC Intertie is greater than 3200 MW up to and including 4800 MW, Portland's share of Rated Transfer Capability shall be the share specified in subsection 7(a) plus a share of the increased Rated Transfer Capability in the

ratio of 150/1600 times the increase in Rated Transfer Capability above 3200 MW. As between Bonneville and Portland, Bonneville's share of the Rated Transfer Capability shall be the share specified in subsection 7(a) plus a share of the increased Rated Transfer Capability in the ratio of 1450/1600 times the increase in Rated Transfer Capability above 3200 MW.

(c) Rated Transfer Capability greater than 4800 MW. Bonneville and Portland agree that any project to increase the Rated Transfer Capability of the Northwest AC Intertie above 4800 MW shall only be accomplished by distributing the increased Rated Transfer Capability such that at least two-thirds of the increase is distributed to the Joint AC Intertie. Portland shall have the right to participate in any such project to increase the Rated Transfer Capability of the Northwest AC above 4800 MW if Portland chooses to share in such increases. If so, both Portland's cost sharing and increased share of Rated Transfer Capability shall be at a ratio of 950/3200 of the project costs and increased Rated Transfer Capability so attributed to the Joint AC Intertie. Ownership of facilities providing the increased Northwest AC Intertie Rated Transfer Capability shall be determined by negotiation with and between facility owners.

8. Transmission Rights.

(a) Determination of Rated Transfer Capability and Operational Transfer Capability. Bonneville and Portland shall jointly determine the Rated Transfer Capability of the Joint AC Intertie. Portland agrees that Bonneville may determine the Rated Transfer Capability of the Northwest AC Intertie, provided such determination is in keeping with Prudent Utility Practice, and further provided that Bonneville consults with Portland and reasonably incorporates Portland's technical opinion.

(b) Intertie Scheduling Rights.

(1) During times when the Northwest AC Intertie Operational Transfer Capability is less than the Northwest AC Intertie Rated Transfer Capability, Bonneville and Portland's scheduling rights shall be limited to an amount determined by multiplying the Northwest AC Intertie Operational Transfer Capability by the ratio of the party's share of Northwest AC Intertie Rated Transfer Capability to the total Northwest AC Intertie Rated Transfer Capability.

(2) Bonneville and Portland, as between each other, have the exclusive right to use their own share of Northwest AC Intertie Operational Transfer Capability to schedule power or energy for delivery to and from Pacific Southwest utilities without regard to the ownership of the power or energy scheduled and hereby relinquish any rights to make use of the other party's Unused Operational Transfer Capability. Either party, at its discretion, may make its Unused Operational Transfer Capability available to the other party so that the other party may schedule up to its Rated Transfer Capability.

(c) Portland's Rights to Access at Southern Oregon Substation.

(1) Once the Southern Oregon Substation, and the facilities connecting it to the Joint AC Intertie, and the COTP, and the facilities connecting it to the Southern Oregon Substation, are in operation such that the Rated Transfer Capability of the Northwest AC Intertie has been increased to above 3200 MW, Portland shall have the right to schedule power or energy for delivery at all times to and from Pacific Southwest utilities through the Southern Oregon Substation as follows:

(A) If the COTP and the presently existing AC Intertie lines in California are operated as a single system (i.e., integrated with the

existing AC Intertie system such that there is an equivalent sharing among the COTP owners and existing intertie owners of transfer capability under all conditions), Portland may schedule up to its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1).

(B) If the COTP and the presently existing AC Intertie lines in California are not operated as a single system, Portland may schedule up to one third of its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1).

(2) Such delivery right is intended to continue upon the terms and conditions specified in this subsection 8(c) for as long as the Southern Oregon Substation and the facilities connecting it to the COTP are in existence and operable and Bonneville has rights to schedule to Southern Oregon Substation. Should this Agreement terminate earlier than specified in subsection 2(a) for any reason except material breach of contract by either party, and the parties fail to agree to a replacement agreement, the rights of Portland under this subsection 8(c) shall survive for the period stated above, contingent upon Portland's satisfaction of its payment obligation under paragraph 8(c)(3). Therefore, other than as excepted above, the parties intend this obligation to survive such earlier termination.

(3) In consideration for the right to make deliveries to Southern Oregon Substation in paragraph 8(c)(1), Portland shall pay Bonneville 950/4800 of the annual cost of the Southern Oregon Substation, facilities connecting it to the Joint AC Intertie and the facilities connecting the Southern Oregon Substation to the COTP. All such facilities and their estimated costs are shown in Exhibit F. Bonneville and Portland agree

that the estimated investment costs and resultant annual costs shall be revised to reflect actual construction costs. The methodology to compute the annual cost of such facilities is described in Exhibit F and an example of the calculation applying such methodology is provided in Exhibit F. Such annual charge shall be billed and paid on a monthly basis according to the billing and payment provisions in Portland's Power Sales Agreement (Contract No. DE-MS79-81BP90425).

(4) Bonneville shall maintain the Southern Oregon Substation, the facilities connecting it to the Joint AC Intertie, and the facilities connecting the Southern Oregon Substation to the COTP according to Prudent Utility Practice so as to sustain their ability to transfer power and energy. In the event that these facilities are unable to transfer power and energy as a result of Bonneville's failure to maintain or replace such facilities such that Portland cannot transfer its share of Rated Transfer Capability, as such share may be reduced pursuant to paragraph 8(b)(1), through the Southern Oregon Substation for a period in excess of 120 days, then Portland shall be obligated to pay the annual charge specified in paragraph 8(c)(3) minus one-half the annual charge divided by 365 days times the number of days in which Portland is unable make such transfers (annual charge - [(1/2 annual charge/365 days) X days Portland is unable to schedule at Southern Oregon Substation]).

(d) FCRTS Wheeling to Northwest AC Intertie.

(1) Except as provided in paragraph 8(d)(2), all of Portland's schedules to Pacific Southwest utilities on the Northwest AC Intertie shall be deemed to be delivered at John Day Substation, or if Bonneville establishes other Northwest AC Intertie points of delivery, at Portland's

request such deliveries may be deemed to be delivered to such other points of delivery.

(2) Except when Portland is accepting schedules under the provisions of paragraph 8(d)(3), up to the greater of 150 MW of Portland's schedules to Pacific Southwest utilities, or an amount equal to the actual energy produced from Portland's Round Butte and Pelton projects when those projects are actually producing energy, not to exceed the capacity of the transformer for the Round Butte-Grizzly line, shall be deemed to be delivered over Portland's facilities to the Grizzly Substation.

(3) Portland can schedule power and energy from Pacific Southwest utilities over the Grizzly-Bethel line up to the actual east to west flow on the Grizzly-Round Butte line as metered at Grizzly.

(4) Transmission arrangements over the FCRTS, other than the Joint or Northwest AC facilities, shall be as provided in subsection 15(c).

9. Modification of and Addition to Facilities.

(a) Unless it has obtained the written consent of the other party, such consent not to be unreasonably withheld, neither party shall make any modifications, additions, improvements, or other alterations to facilities in the Joint AC Intertie. Ownership of modifications, additions, improvements, or other alterations made with such consent shall be as specified in the Malin Construction and Operation Agreement, the Grizzly Trust Agreement, and the Grizzly Construction Trust Agreement, where appropriate, or as agreed by the parties in advance of the performance of such work.

(b) Portland and Bonneville hereby consent to a Plan-of-Service for modifications and additions to the Joint AC Intertie to increase the Rated Transfer Capability of the Northwest AC Intertie to 4800 MW provided that such Plan-of-Service conforms to the Third AC Intertie Project Diagram,

incorporated herein as Exhibit C. Bonneville and Portland shall share, in accordance with the percentages specified in Exhibit B, the actual cost of the facilities identified in the Plan-of-Service.

(c) In the event this Agreement terminates for any reason and implementation of such Plan-of-Service causes Portland to lose its physically and electrically connected transmission path through facilities in which it has ownership, from its service territory via Round Butte, through Grizzly substation to Malin substation over the Grizzly-Malin Number 2 line, Bonneville agrees to restore and share equally the costs of such restoration of Portland's continuous connection of facilities owned by Portland.

(d) Portland agrees that Bonneville shall have the right to plan, design, locate, construct, and own the Southern Oregon Substation and associated interconnection to the COTP. Should the basic configuration of the Southern Oregon Substation materially change from that shown in Exhibit C such that Portland's access under subsection 8(c) to the substation and the Pacific Southwest utilities is reduced or such that Portland's charges under paragraph 8(c)(3) substantially increase, then Bonneville will seek Portland's consent, such consent not to be unreasonably withheld.

(e) Portland hereby consents to any modifications consistent with Prudent Utility Practice to the Joint AC Intertie, at Bonneville's expense, necessary to accomplish the DC Terminal Expansion project up to a total DC Intertie Rated Transfer Capability of approximately 3100 MW, including the modifications shown in Exhibit A.

(f) Bonneville and Portland hereby consent to undertake those modifications to facilities in the Joint AC Intertie, as specified in Exhibit A, necessary to implement the reliability improvement projects. Portland shall permit Bonneville to make the modifications to the Malin,

Grizzly, and Fort Rock Substations specified in Exhibit A, or Portland shall make such modifications. Portland shall pay the share of the actual costs of the modifications specified in Exhibit A. Bonneville and Portland's ownership of such modifications at Malin and Grizzly shall be equal to the percentages specified in Exhibit A.

10. Financing by Portland

(a) At Bonneville's request, Portland shall arrange to finance Bonneville's costs associated with the development of the project to increase the Northwest AC Intertie Rated Transfer Capability from 3200 MW up to approximately 4800 MW as provided for in this Agreement.

Such request shall be made in writing and Portland shall make such arrangements within 60 days after mutual consultations on alternatives. (Time is of the essence.) Bonneville shall have the right to approve or disapprove such arrangements prior to the sale or issuance of any obligation or financing arranged by Portland pursuant to this paragraph.

(b) The proceeds of any financing, net of issuance costs, shall be paid into a trust. Bonneville and Portland shall mutually agree on a form of trust agreement and the selection of a trustee. The trustee shall pay construction costs or amounts owing to Portland, as applicable, together with payments of any capitalized carrying financing costs incurred during construction and capitalized carrying costs on such costs, if any.

(c) Portland shall attempt to obtain the least possible cost financing available. Portland shall not be required to seek financing based on its own credit unless financing based solely on Bonneville's payment obligation is not available. Portland need not make available to Bonneville any financing opportunities that Portland intends to use to finance other Portland costs or to retire Portland debt. Portland will not use any financing opportunity that

results from any financing proposal made at Bonneville's request to finance any other Portland costs.

(d) Portland need not attempt any formal financing that: (a) may cause Portland General Corporation to become a nonexempt Holding Company under the Public Utility Holding Company Act of 1935, 15 USC §79 et. seq.; (b) would be contrary to the restrictions of any law, regulation, judicial decree, or order of any applicable jurisdiction; or (c) would be contrary to any Portland bond indenture, preferred stock covenant, or other Portland financial commitment.

(e) Bonneville shall make all financing payments as stipulated in the mutually agreed upon financing arrangement.

11. Maintenance of Facilities.

(a) Each party is responsible for performing maintenance on and reinforcing its respective solely owned facilities so as to maintain the Rated Transfer Capability of the Northwest AC Intertie. Maintenance on the jointly owned facilities at Grizzly and Malin substations are provided for in the Grizzly Operation and Maintenance Trust Agreement and the Malin Operations and Maintenance Trust Agreement, respectively.

(b) Each party is responsible for performing maintenance on its respective existing facilities so as to maintain the Rated Transfer Capability of the existing DC Intertie and the DC Terminal Expansion. Bonneville is responsible for performing maintenance on the existing DC Intertie facilities and the DC Terminal Expansion facilities so as to maintain the Rated Transfer Capability of the Northwest AC Intertie.

(c) Each party shall carry out the requirements of section 11 consistent with Prudent Utility Practice.

(d) Bonneville and Portland shall negotiate in good faith a separate joint maintenance agreement for the jointly owned facilities of the Joint AC

Intertie to replace the existing agreements for maintenance.

12. Scheduling.

(a) Bonneville and Portland shall schedule through the Joint Intertie Scheduling Office all schedules to and from utilities in the Pacific Southwest to be delivered at the Malin and Southern Oregon Substations.

(b) Portland shall provide the Joint Scheduling Office an actual schedule of the generation at the Round Butte and Pelton projects by 1000 hours of the following workday for the previous day or days. Such schedule shall be consistent with section 8(d)(2) of this Agreement.

13. Northwest AC Intertie Charges.

(a) Charges for Portland's Own Schedules. Bonneville shall not assess Portland any charge to schedule power and energy for delivery to and from Pacific Southwest utilities over the Northwest AC Intertie on any hour up to Portland's share of the Rated Transfer Capability, as such share may be reduced pursuant to subsection 8(b)(1).

14. Losses. Bonneville and Portland shall replace losses for schedules on the Northwest AC Intertie as provided in Exhibit E.

15. Other Agreements.

(a) Agreement to an Exchange of Rights of Use of AC for DC Capability. Bonneville and Portland agree to terms and conditions for an exchange of the right to use a amount of Portland's share of the Northwest AC Intertie Rated Transfer Capability for a right to use an equal amount of Bonneville's DC Intertie Rated Transfer Capability as provided in Exhibit D to this Agreement.

(b) General Transfer Agreement. Bonneville and Portland agree to ~~the~~ negotiate a new general transfer agreement to be executed by January 1, 1989. During the negotiation period, Bonneville and Portland agree to continue the

existing transfer services according to the terms and provisions of Contract No. DE-MS79-83BP91011 as such agreement has been amended.

(c) IR Agreement.

(1) Bonneville and Portland shall negotiate in good faith a general transmission agreement (IR Agreement) to be executed by January 1, 1989. Such agreement shall be executed concurrently with the general transfer agreement and shall include provisions for delivery from Portland's resources to the Northwest AC and DC Intertie points of delivery as well as to Portland's system points of delivery.

(2) Deliveries of power and energy over the FCRTS to points of delivery at the Northwest AC Intertie are not provided by this Agreement and must be provided for by separate agreement between Bonneville and Portland. However, until January 1, 1989, Bonneville agrees to provide Portland with the right to deliver energy to the Northwest AC Intertie point of delivery which would otherwise be delivered to Portland's system as specified in Contracts Nos. 14-03-001-13437, 14-03-001-13773, 14-03-28002, and 14-03-41848 (Mid-Columbia Agreements) subject in all other respect to the applicable terms and conditions of such agreements. After January 1, 1989, if an IR Agreement and a general transfer agreement have not been executed, half of Portland's schedules to the Northwest AC Intertie point of delivery will continue as specified above, but the other half of Portland's schedules shall be required to be delivered at Portland's system and shall be subject to Bonneville's rate schedule for nonfirm transmission and losses for subsequent delivery to the Northwest AC Intertie point of delivery, unless otherwise agreed by Bonneville and Portland.

(d) Extension of Existing Agreements. Bonneville and Portland agree that for the purpose of defining the term of the Malin Construction and Operations Agreement, Malin Operation and Maintenance Trust Agreement, and Grizzly Operation and Maintenance Trust Agreement, this Agreement shall be considered to be a renewal by a similar agreement of the Intertie Operations Agreement and the Intertie Settlement Agreement.

(e) Agreements for Implementation of this Agreement. In addition to the above agreements, Bonneville and Portland agree to negotiate in good faith any additional agreements that may be required to implement the terms and conditions of this Agreement, including but not limited to agreements for transmission, and operation and maintenance.

16. Sale or Assignment.

(a) Portland or Bonneville may sell, assign, lease, sublease or otherwise transfer (all hereafter referred to as "transfer") this Agreement, any interest herein or any direct or indirect interest in the Joint AC Intertie facilities or facilities directly affecting the Joint AC Intertie, without the consent of the other party, provided

(1) the agreement by which the transfer is accomplished contains the following language:

"Anything contained in this Agreement to the contrary notwithstanding, the transferor does not by this Agreement transfer any rights or obligations with respect to any of the following activities, and hereby specifically retains all such rights and obligations:

(A) scheduling the use of the transferor's interest (including the interest transferred herein) in the Joint AC Intertie as that interest is established pursuant to the Intertie Agreement between

Portland General Electric Company and the Bonneville Power Administration (Contract No. DE-MS79-87BP92340) executed July 29, 1988, as amended;

(B) operation, maintenance and repair of the Joint AC Intertie facilities (as defined in the Intertie Agreement);

(C) renewals, replacements and additions to the Joint AC Intertie facilities; and

(D) system planning for the Joint AC Intertie."

"Subsequent involuntary transfer, by law or otherwise, of any rights or obligations with respect to any of the foregoing activities shall be subject to the non-transferring owner's prior right to preclude such transfer by, at its election,

(i) remedying any and all defaults; or

(ii) acquiring the interest herein transferred at fair market value and assuming the rights and obligations respecting the foregoing activities."; and

(2) the agreement grants third party beneficiary status to the nontransferring owner with respect to enforcement of the above provisions.

(b) Notwithstanding the provisions of subparagraphs 16(a)(1)(B) and (C) above, the transferor may covenant to the transferee to perform maintenance to keep the Joint AC Intertie facilities in good working order pursuant to Prudent Utility Practice, and to maintain the Rated Transfer Capability (as defined in the above Intertie Agreement between Portland and the Bonneville) of the Joint AC Intertie.

(c) Portland or Bonneville may transfer this Agreement, any interest herein or any direct or indirect interest in the Joint AC Intertie facilities

to an entity or entities if the transferring party is acquired in total by such other entities.

(d) Except as provided in subsections 16(a) and (c) above, Portland and Bonneville agree not to transfer this Agreement, any interest herein, any interest in the Joint AC Intertie facilities or any rights or obligations with respect to the activities listed in paragraph 16(a)(1) above without the written consent of the other party, such consent not to be unreasonably withheld. Wheeling and other transmission contracts which do not transfer legal rights or obligations with respect to scheduling, operations, maintenance, repair, improvement, modification or system planning of the Joint AC Intertie to other parties shall not be considered transfers of interests in this Agreement or in the Joint AC Intertie facilities. Scheduling of wheeling obligations shall be retained by Portland and Bonneville.

(e) A party proposing to transfer an interest in this Agreement or in the Joint AC Intertie facilities shall provide the other party at least 30 days notice prior to the earlier of: (1) the execution of the transfer or grant documents; or (2) filing of the proposed transfer with FERC or its successor agency, if such transfer must be filed with FERC. The party shall provide with such notice a description of the terms and conditions of the proposed transfer sufficient to allow the other party reasonable opportunity to evaluate the proposed transfer with respect to the requirements of this section (including the position of the party giving notice as to whether consent is required pursuant to subsection 16(d)), and shall thereafter provide to the other party copies of all final documents comprising the transfer agreement as early as possible prior to their execution. If the information provided is considered by the party providing such information to

be proprietary and confidential, it shall label such information as proprietary and confidential. The party receiving the above information shall exert best efforts to keep all such labeled information confidential until it has been made public by the other party or others. The receiving party shall take steps necessary to have the information declared "proprietary" or otherwise categorized so as to protect such information from public disclosure to the extent legally allowable under the Federal Freedom of Information Act or similar applicable law or regulation.

(f) The nontransferring party shall notify the other party by the 30th day following actual receipt of the notice and description described in subsection 16(e) (or, if not a working day, the first working day thereafter) of its grant or withholding of consent requested pursuant to subsection 16(d) or its approval or disapproval of a transfer proposed to be made pursuant to subsection 16(a); provided, however, that such time shall be extended to 5 working days after actual receipt of copies of the final documents comprising the transfer or grant if receipt of such documents is on or after the 26th day of the 30-day period and such final documents reflect material changes from documents provided prior to such 26th day. Failure to provide notice of withholding of consent or disapproval within such required periods shall be deemed a grant of consent or approval, as the case may be. The nontransferring party shall be allowed to attend the closing of the transfer and retain all executed copies of its approval until it is satisfied that the final documents do not exhibit material changes from the documents provided earlier. If a party withholds any required consent or disapproves, then such party shall, within 15 days following notice of such withholding or disapproval, provide to the party requesting consent or approval a detailed

written description of the reason(s) consent or approval was withheld.

(g) Portland and Bonneville agree that in the event of any dispute between them concerning the application of this section 16 they shall cooperate fully with each other to obtain final judicial resolution of such dispute in the most expeditious manner possible.

(h) Bonneville hereby consents to Portland's transfers of security interests in this Agreement and the Joint AC Intertie facilities pursuant to the Indenture of Mortgage and Deed of Trust dated July 1, 1945, between Portland and the Marine Midland Trust Company of New York, as supplemented.

(i) The restrictions contained in this section 16, and exceptions thereto, shall apply to any transferee to the same extent they are applicable to the parties to this Agreement.

(j) Transfers of any interest in this Agreement or in the Joint AC Intertie facilities that do not meet the requirements of this section 16 shall be void.

(k) The provisions of this section 16 shall not survive termination of this Agreement.

17. Rules of Law.

(a) Portland and Bonneville agree that each fully participated in the drafting of each provision of this Intertie Agreement. The rule of law interpreting ambiguities against the drafting party shall not be applicable to or utilized in resolving any dispute over the meaning or intent of this Intertie Agreement or any of its provisions.

(b) The construction and interpretation of this Intertie Agreement shall be governed solely by Federal law.

(c) This Intertie Agreement shall not be construed to establish a partnership, association, joint venture, or trust. Neither party shall be

under the control of or shall be the agent of or have a right or power to bind the other party without the other's express written consent, except as provided in this Intertie Agreement.

18. Delay of Performance. The time for each act specified in this Intertie Agreement shall be extended for a time equivalent to such delays, if any, as are occasioned by events which the party hereto obligated to perform such act could not be reasonably expected to avoid by the exercise of reasonable diligence and foresight.

19. Continuity of Service.

(a) Either party may temporarily interrupt or reduce deliveries hereunder if such interruption or reduction is necessary or desirable in case of system emergencies, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the electric system of such party. Except in case of emergency and in order that the other party's operations will not be unreasonably interfered with, notice shall be given of any such interruption or reduction, the reason therefore, and the probable duration thereof.

(b) If the operation of either party's transmission system is suspended, interrupted, or interfered with as the result of the occurrence of any event that is specified in subsection 19(a) or any event that is reasonably beyond such party's control (including, but not limited to, the failure or breakdown of generating or transmission facilities, floods, fire, strikes, or acts of God or the public enemy), it shall not be obligated to make deliveries as provided in this agreement, during such time and to such extent as such suspension, interruption, or interference makes it reasonably impracticable to do so, and shall not be liable for any damages sustained by the other party as a result of the failure to make such deliveries during such time.

(c) If the operations of either party are interrupted or curtailed, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

20. Arbitration. In the event of any dispute related to rights or obligations of the parties, or satisfaction thereof, under this Agreement, other than disputes arising under section 16, either party may elect to submit such dispute to nonbinding arbitration. If one party so elects, such party shall notify the other party in writing and both parties shall participate pursuant to the following.

(a) If the parties cannot agree on an arbiter within 10 days of such notification, the notifying party shall request the American Arbitration Association to designate an arbiter with sufficient expertise in the subject under dispute.

(b) After an arbiter is agreed to or designated, the arbiter shall establish a schedule for submission of the parties' written positions. The party electing the arbitration shall first state its position in a letter to the arbiter. The second party shall then state its position in a letter to the arbiter. The first party may then submit a response to the second party's position and the second party may thereafter submit a reply to the first party's response.

(c) Each letter submitted to the arbiter shall be no more than 5 pages in length, unless the parties otherwise mutually agree. The parties may attach exhibits that they consider relevant to the dispute. A copy of each submission also shall be simultaneously served on the other party.

(d) The arbiter shall provide the parties with a written analysis of the dispute, and his or her proposed resolution of the dispute.

(e) The parties shall equally share the fee and other costs of the arbiter.

In the event neither party submits the dispute to nonbinding arbitration or if either party elects not to accept the finding of the arbiter, the parties may elect other approaches, including litigation, to resolve the dispute.

21. Metering.

(a) Measurement. Measurement of electric energy and reactive power and of the 60-minute integrated demands for such electric energy flowing between Bonneville's facilities and Portland's facilities at the Grizzly substation shall be determined from measurements made by meters furnished and installed by Bonneville and Portland as agreed.

(b) Test of Meters. Each party to this Agreement shall, at its expense, test its meters mentioned in this Agreement periodically, and, if requested to do so by the other party, shall make additional tests or inspections of such meters, the expense of which shall be paid by such other party unless such additional tests or inspections show such meters to be inaccurate as specified in subsection 21(c). Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Metering equipment found to be defective or inaccurate in any degree shall be adjusted, repaired, or replaced to provide accurate metering.

(c) Adjustment for Inaccurate Metering. If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in subsection 21(b) varies by more than one percent from the measurement made by the standard meter for: (a) the actual period, not to

exceed 6 months, during which such inaccurate measurements were made if such period can be determined; or (b) if not, the period immediately preceding the test of such meter which is equal to one-half the time from the date of the last preceding test of such meter. Such corrected measurements shall be used to recompute the amounts due for the electric energy made available under this contract during such period. If the total amount due for such period as recomputed varies from the total amount due as theretofore computed, the amount of the variance shall be paid to the party entitled thereto within 30 days after the recomputation is made.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By James J. Jura
Administrator

Date July 29, 1988

PORTLAND GENERAL ELECTRIC COMPANY

By

Title Vice President

Date June 29, 1988

(VS6-PMT-2692d)

Sharing of Costs for Reliability Improvements and Other Projects

Description	Planned Energization Date	Total ($000)	PGE Share
1. Reliability Improvements			
Phase 2 (Stability Control Upgrade): Provide new remedial action schemes (RAS) for the AC Intertie and HVDC Intertie. This phase completes a new fully redundant RAS for the HVDC Intertie (two independent control and communication systems). Also this phase will provide the first controller of the new AC Stability Control Scheme including communications support. Output for the second controller (to be installed in Phase 3) are also provided in this phase.			
a. Malin	Jan 1990	932	25%
b. Grizzly	Jan 1990	480	40%
c. Fort Rock	Jan 1989	99	50%
Phase 3 (Stability Control Upgrade): Provide a new AC Intertie stability control system to replace the existing AC Intertie controller. This new control system will utilize some of the communication systems provided under Phase 2. This will complete a fully redundant RAS for the AC Intertie.			
a. Malin	Jan 1990	448	25%
b. Grizzly	Jan 1990	302	40%
2. DC Terminal Expansion Related Projects			
Install a mechanically switched capacitor at Malin Substation	Feb 1989	6,000	0%
Restore High Speed Switching at Fort Rock Compensation Station.	Feb 1989	272	1/

1/ Cost sharing responsibilities shall be as provided in Letter Agreement No. DE-MS79-88BP92446. Ownership of facilities shall be entirely with Portland.

(VS6-PMT-2692d)

Sharing of Costs for Plan-of Service in Joint AC Intertie
1988 ($)

Facility	Estimated Total Cost X 10 3/ [1/]	Allocation PGE	Allocation BPA
Grizzly Substation			
7 PCB's	7309	0%	100%
1 PCB (Round Butte) and associated MOD's	1123	100%	0%
Line Relaying (Grizzly-S. Oregon, Grizzly-Malin #2, Grizzly-J.D. #1 Grizzly-J.D. #2, Grizzly-Buckley Grizzly-S. Lake) and Power System Control, Communication and Data System Facilities	3931	27%	73%
Sand Spring Compensation Station			
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-So. Oregon)	9695 2/	0%	100%
1 - 2400A Cont., 3800A 30 Min. Rated Bank(Grizzly-Malin #2)	6500 5/	100%	0%
Fort Rock Compensation Station			
1 - 2200A Cont., 3000A 30 Min. Rated Bank (Grizzly-So. Oregon)	6277 2/	0%	100%
1 - 2200A Cont., 3000A 30 Min. Rated Bank (Grizzly-Malin #2)	4700 5/	100%	0%
Sycan Compensation Station			
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-So. Oregon)	9535 2/	0%	100%
1 - 2400A Cont., 3800A 30 Min. Rated Bank (Grizzly-Malin No. 2)	6500 5/	100%	0%

Facility	Estimated Total Cost X 10 3/ [1/]	Allocation PGE	Allocation BPA
Malin Substation			
Line Relaying Malin-S. Oregon (formerly Grizzly-Malin No. 1) Grizzly-Malin No. 2 line and Power System Control, Communication and Data System Facilities	2249	25%	50% 3/
Replace one 500 kV breaker and associated MOD's	775	0%	100%
Line relaying for Malin-S. Oregon #2	211	0%	50% 4/
John Day Substation			
Line Relaying for J.D.-Grizzly #1 & #2, Relaying for Breakers, CT Repl. Power system Controls	2808	0%	100%
Bakeoven Compensation Station			
(Removal and Disposal Costs Only)	1800	0%	100%

1/ Estimated costs include overheads assumed at 30%. Estimated costs are subject to inflation, escalation and minor changes to the plan-of-service.
2/ Estimated costs include removal and disposal costs for PCB contaminated facilities ($600K)
3/ BPA's share is 50%, PGE's share is 25%, PP&L's share is 25%.
4/ BPA's share is 50%, PP&L's share is 50%.
5/ Costs shown are PGE estimates, exclusive of overheads and removal and disposal costs for PCB contaminated facilities.

(VS6-PMT-2692d)

LOWER COLUMBIA AND SNAKE RIVER AREAS

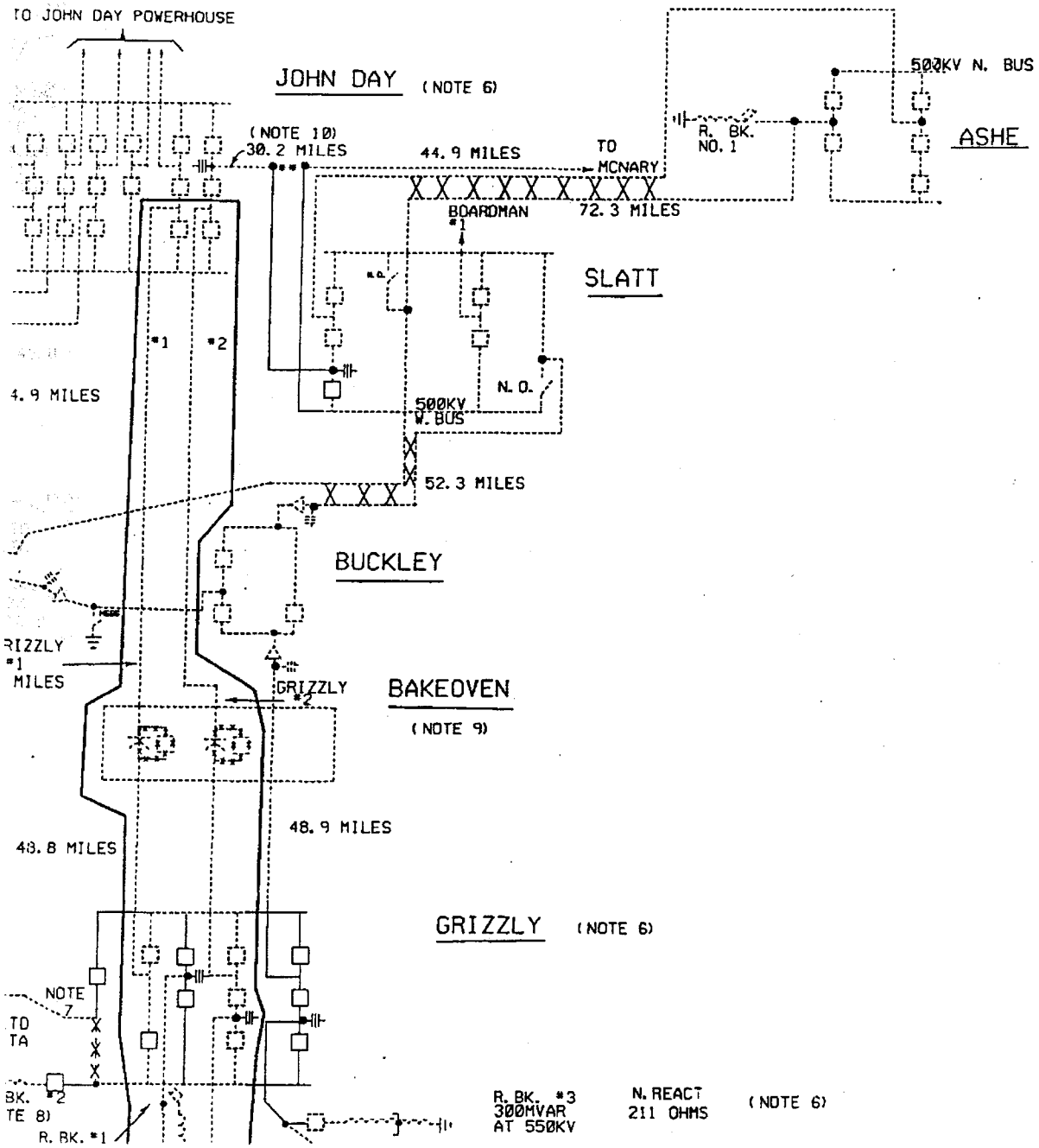


EXHIBIT C, PAGE 1 OF 1
CONTRACT NO. DE-MS79-87BP92340
PORTLAND GENERAL ELECTRIC

NOTES:

1. THIS DIAGRAM SHOWS A NUMBER OF LOAD SERVICE FACILITIES WHICH ARE NOT PART OF THE THIRD AC INTERTIE PROJECT.

2. FOR MORE DETAILED INFORMATION ON THE INDIVIDUAL STATIONS INVOLVED, REFER ALSO TO SHEETS 2 TO 11 AND DRAWING NO. 196480 (EUGENE-MEDFORD PROJECT).

3. TRANSFORMERS SHOWN ARE POTENTIAL ADDITIONS BY PP&L BUT NOT REQUIRED FOR THE THIRD AC INTERTIE PROJECT.

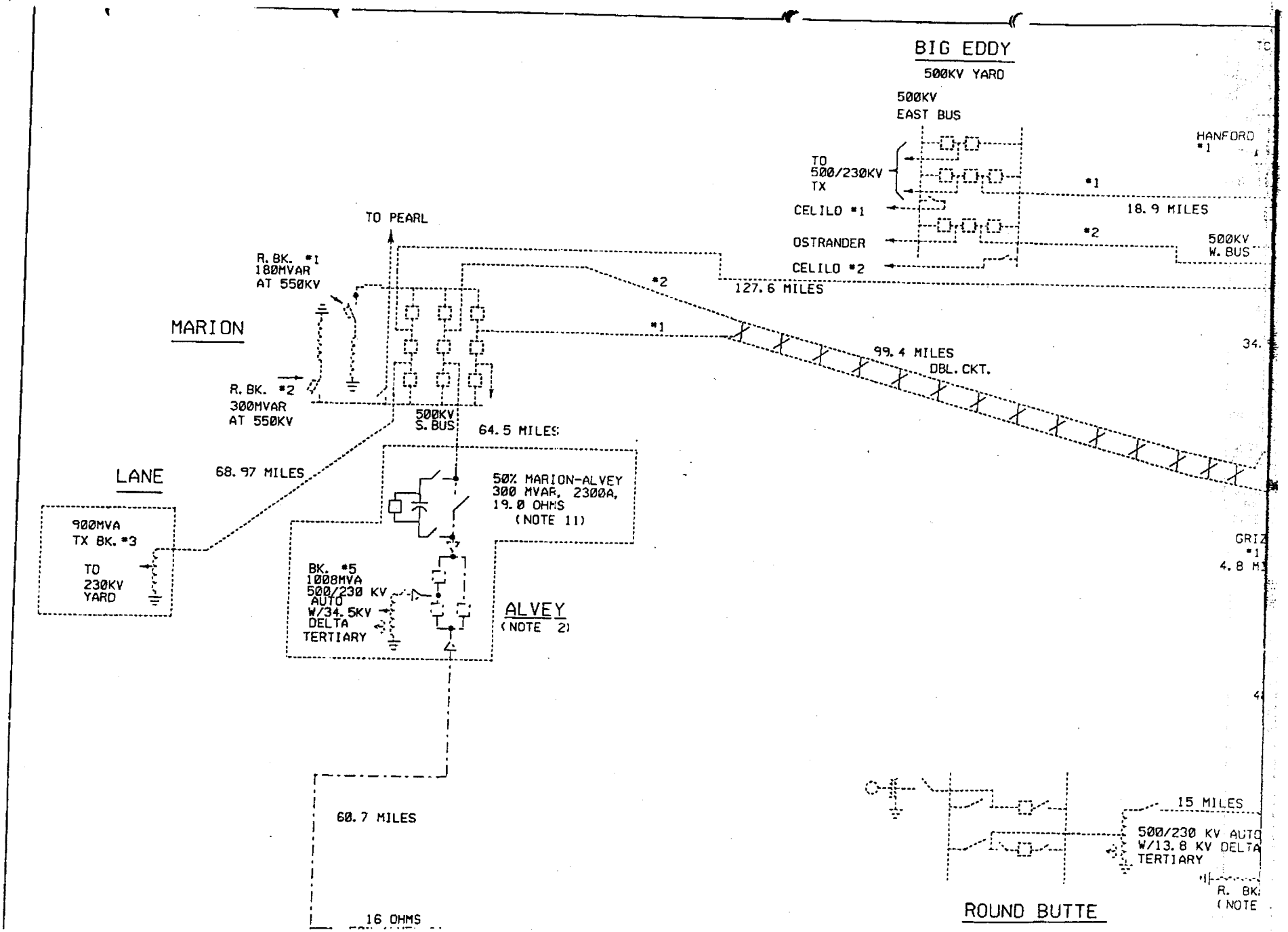
4. TWO 500KV CIRCUIT BREAKERS ADDED AT MALIN ARE ASSOCIATED WITH OVERALL IMPROVEMENT OF INTERTIE PERFORMANCE AND BUDGETED UNDER B.I. 880.

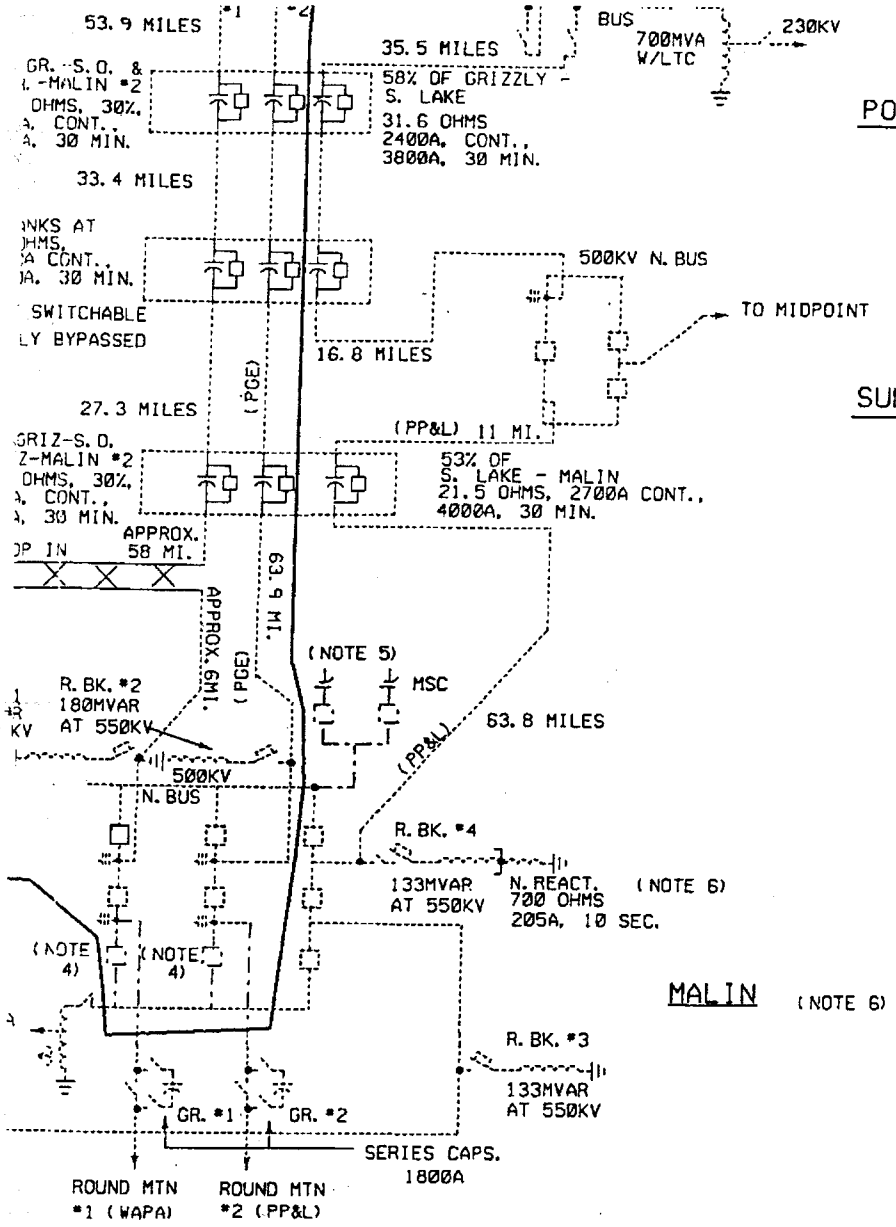
5. MECHANICALLY SWITCHED CAPACITORS (MSC) REQUIRED FOR THE D.C. TERMINAL EXPANSION PROJECT AND BUDGETED UNDER B.I. 150. FY 87.

6. HYBRID SINGLE POLE RELAYING WILL BE INSTALLED BY BPA ON THE J. DAY-GRIZZLY LINES 1 & 2 & THE GRIZZLY-S. OREGON LINE. PGE TO ALSO INSTALL HYBRID SPR ON THE GRIZZLY-MALIN #2 LINE, PROVIDED NO ADDITIONAL SECONDARY ARC EXTINCTION EQUIPMENT IS REQUIRED.

   THE EXISTING FOUR REACTOR SPR SCHEME WILL BE MAINTAINED ON THE GRIZZLY -SUMMER LAKE AND SUMMER LAKE-MALIN CIRCUITS.

7. PGE TO INSTALL A BREAKER IN THE EXISTING BAY 5 WHERE THEIR ROUND BUTTE LINE IS TERMINATED. PGE TO REMOVE EXISTING BREAKER AND BPA TO INSTALL NEW BREAKER IN BAY 4 SOUTH BUS POSITION.


BIG EDDY
500KV YARD
500KV
EAST BUS
TO
500/230KV
TX
CELILO *1
OSTRANDER
CELILO *2
HANFORD
*1
*1
18.9 MILES
*2
500KV
W. BUS
127.6 MILES
TO PEARL
R. BK. *1
180MVAR
AT 550KV
MARION
R. BK. *2
300MVAR
AT 550KV
500KV
S. BUS
*2
*1
99.4 MILES
DBL. CKT.
64.5 MILES
68.97 MILES
LANE
900MVA
TX BK. *3
TO
230KV
YARD
50% MARION-ALVEY
300 MVAR, 2300A,
19.0 OHMS
(NOTE 11)
BK. *5
1008MVA
500/230 KV
AUTO
W/34.5KV
DELTA
TERTIARY
ALVEY
(NOTE 2)
60.7 MILES
16 OHMS
15 MILES
500/230 KV AUTO
W/13.8 KV DELTA
TERTIARY
ROUND BUTTE



THE SERIES CAPACITORS, HOWEVER, WILL NOT OCCUR UNTIL AFTER THE PROJECT ENERGIZATION. UNTIL IT IS DECIDED WHEN TO REMOVE THE CAPACITORS THE STATION WILL OPERATE IN A PERMANENT BYPASSED MODE.

10. THE 2½ INCH ACSR LINE SECTIONS TO BE RECONDUCTORED ALONG THE SLATT-JOHN DAY LINE.

11. SERIES CAPACITORS AT ALVEY, DIXONVILLE AND MERIDIAN ARE REQUIRED FOR THE THIRD AC INTERTIE.

12. ALVEY 500KV SUBSTATION DEVELOPMENT AND ALVEY-SPENCER 500KV LINE SECTION BUDGETED UNDER B.I. 102, EUGENE-MEDFORD 500KV INTERCONNECTION. REFER ALSO TO DRAWING NO. 196480.

13. SOUTHERN OREGON SUBSTATION IS TO BE DESIGNED, OWNED, INSTALLED AND OPERATED BY BPA. PP&L WILL, HOWEVER OWN THE LINE TERMINALS WHERE THEIR MALIN-MERIDIAN LINE TERMINATES, INCLUDING TWO BREAKERS. THE SIX MILES OF LINE FROM S. OREGON TO THE BORDER WILL BE DESIGNED AND INSTALLED BY TANC AT BPA COST BUT OWNED BY BPA.

NO.	COMPUTER REVISION ONLY	COORD ENGR	OM&C	AREA	APPROVED

PROJECT DIAGRAM

FISCAL YEAR PROG.	BUDGET ITEM
87	103

ENERGIZATION DATE(S)
10/91

COORD. ENGR.	CHECKED EOFA
LWM	MAR 6/16/88
CONTROL PD	CHECKED EEP
	LH

OM&C CONCURRENCE
TMS/WLM 6/16/88

AREA CONCURRENCE
EAP 6/16/88 RG 6/16/88

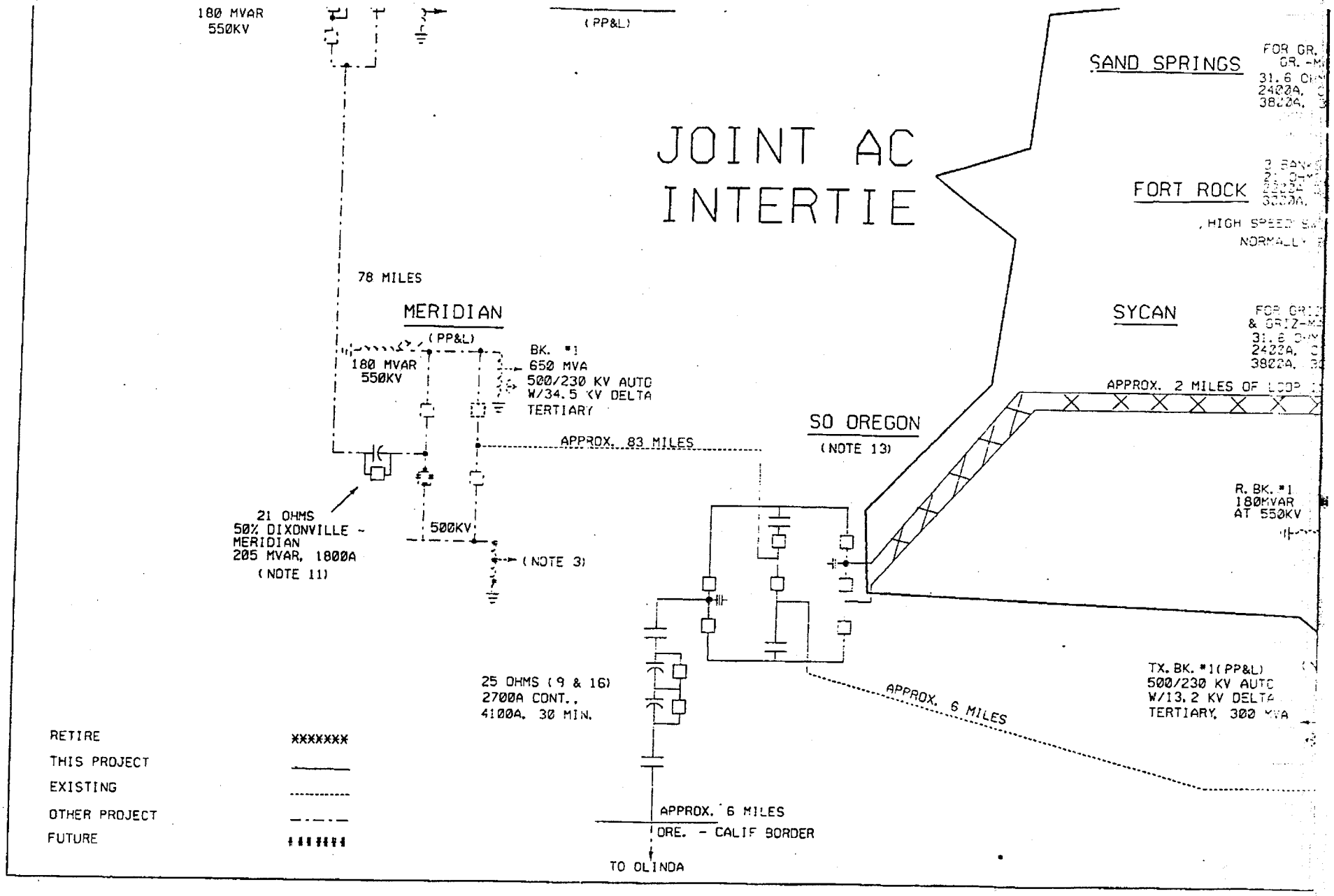
APPROVED
DM PORTER 6/17/88
CHIEF, TRANS. PLANNING BRANCH

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
HEADQUARTERS, PORTLAND, OREGON

DIVISION OF SYSTEM PLANNING

THIRD AC INTERTIE
(NORTHWEST)
EASTERN CORRIDOR OPTION

SERIAL	SOURCE	SIZE	SHEET	REVISION
196486	DSP	A1	01 OF 11	0


JOINT AC INTERTIE
180 MVAR 550KV
(PP&L)
SAND SPRINGS
FORT ROCK
SYCAN
78 MILES
MERIDIAN
(PP&L)
180 MVAR 550KV
BK. #1 650 MVA 500/230 KV AUTO W/34.5 KV DELTA TERTIARY
APPROX. 83 MILES
SO OREGON
(NOTE 13)
APPROX. 2 MILES OF LOOP
R. BK. #1 180MVAR AT 550KV
21 OHMS 50% DIXONVILLE - MERIDIAN 205 MVAR, 1800A (NOTE 11)
500KV
(NOTE 3)
25 OHMS (9 & 16) 2700A CONT., 4100A, 30 MIN.
TX. BK. #1 (PP&L) 500/230 KV AUTO W/13.2 KV DELTA TERTIARY, 300 MVA
APPROX. 6 MILES
APPROX. 6 MILES
ORE. - CALIF BORDER
TO OLINDA
RETIRE
THIS PROJECT
EXISTING
OTHER PROJECT
FUTURE

AC/DC Exchange

Bonneville and Portland hereby agree to exchange a right to use Intertie capability wherein Portland shall have a right to use a share of Bonneville's DC Intertie Rated Transfer Capability and Bonneville shall have a right to use an equal amount of Portland's share of Northwest AC Intertie Rated Transfer Capability under the following terms and conditions. Such exchange shall become effective when the parties execute the necessary agreement containing the terms and conditions as outlined in the memorandums of understanding (MOU) between Portland and Bonneville (Contract No. DE-MS79-88BP92375) and between Bonneville, Portland, and the cities of Burbank, Glendale, and Pasadena, California (Cities) (Contract No. DE-MS79-88BP92376).

1. Term. This Exhibit D shall become effective on the date Bonneville sells power to Portland (Exchange Effective Date) under the terms and provisions of Contract No. DE-MS79-88BP92432, and shall terminate the earlier of (a) 25 years from the date of execution of the Contract No. DE-MS79-88BP92376; or (b) the date of termination of the Intertie Agreement.

2. Extension and Termination of Prior Agreement. Portland and Bonneville's short term letter agreement, Contract No. DE-MS79-87BP92374, providing for the short term exchange of a right to use a share of Bonneville's DC Intertie Rated Transfer Capability for a right to use an equal amount of Portland's share of the AC Intertie Rated Transfer Capability shall be extended by this Exhibit D, and shall terminate on the earlier of 2400 hours on September 15, 1988, or the Exchange Effective Date, however, all liabilities accrued thereunder shall be preserved until satisfied.

3. Ownership. Bonneville shall remain the sole owner of the DC Intertie.

4. Operation and Maintenance of the DC Intertie. Bonneville shall have the sole right and responsibility to operate, maintain, and schedule the DC Intertie in the Pacific Northwest.

5. Exchange of a Right to Use.

(a) Portland shall have a right to use up to 100 MW of Bonneville's DC Intertie Rated Transfer Capability and Bonneville shall have a right to use an equal amount of Portland's share of the Northwest AC Intertie Rated Transfer Capability (Initial Exchange).

(b) Such Initial Exchange may, at Portland's request, be increased by up to 100 MW (Additional Exchange), not to exceed a total of 200 MW when combined with the Initial Exchange, after the DC Terminal Expansion

is declared commercial by Bonneville, if Bonneville has not otherwise contractually committed, or is not in negotiations to contractually commit, the uncommitted DC Intertie Rated Transfer Capability to another use.

(c) Such exchange shall reduce Portland's share of the Northwest AC Intertie Rated Transfer Capability specified in subsections 8(a), (b), and (c) of this Intertie Agreement by the total amount of the exchange.

(d) Bonneville's exchange right to Portland's share of the Northwest AC Intertie shall be subject to paragraph 8(b)(1) of this Intertie Agreement.

6. Transmission Rights on the DC Intertie.

(a) On any hour Portland shall have the right to schedule power and energy up to the amount of the Initial Exchange plus the Additional Exchange to and from the Nevada-Oregon border without regard to the source of the power and energy scheduled. However, Portland's use of the DC Intertie shall be subject to provisions of section 7 of the Long-Term Intertie Access Policy issued by Bonneville on May 17, 1988. Portland shall not wheel for other parties on the DC Intertie. Portland's sales of power or energy at the Nevada-Oregon border are not wheeling under this Agreement.

(b) During times when the DC Intertie Operational Transfer Capability is less than the DC Intertie Rated Transfer Capability, and schedules must be reduced, Portland's right to use of a share of Bonneville's DC Intertie Rated Transfer Capability shall be limited to an amount determined by multiplying the Operational Transfer Capability by the ratio of Portland's right to use share of Bonneville's DC Intertie Rated Transfer Capability to the total DC Intertie Rated Transfer Capability.

(c) Deliveries over the FCRTS to the Big Eddy Substation for the DC Intertie shall be subject to the provisions of subsection 8(d) and 15(c) of this Intertie Agreement.

7. Payment Provisions.

(a) Portland shall pay Bonneville an annual charge of $250,000 for Portland's right to use in the Initial Exchange as defined below.

(b) If Portland acquires an Additional Exchange, the annual charge Portland shall pay to Bonneville shall increase to $1,000,000.

(c) The charges in (a) and (b) above shall be divided into 12 monthly installments and be subject to the billing and payment provisions in Portland's power sales agreement (Contract No. DE-MS79-81BP90425).

8. Losses.

(a) Portland shall be responsible for replacing DC Intertie losses to Bonneville at the Nevada-Oregon border under the provisions of Exhibit G.

(b) Portland shall not be responsible for losses resulting from Bonneville's use of Portland's share of the Northwest AC Intertie Rated Transfer Capability as provided in subsection 14(b) of this Intertie Agreement.

9. Assignment. Portland shall have no rights to sell, assign, lease, sublease, or otherwise transfer any right of use in the DC Intertie. Any such transfer without Bonneville's consent shall be null and void.

10. Waiver of Bonneville's Obligation to Serve Load.

(a) Portland agrees that the disposition of Pacific Northwest energy from Portland's resources for use outside of the Pacific Northwest shall result in a reduction of Bonneville's obligation to supply firm energy under section 5(b) of P.L. 96-501 (16 U.S.C. 839c(b), equal to the maximum amount of energy which Portland is obligated to provide for use outside of the Pacific Northwest for the period of such disposition. Bonneville may sell to Portland as replacement for such energy, under the Power Sales Contract, only what would otherwise be surplus energy. Bonneville shall implement such reduction as described in subsection (b) below.

by PORTLAND

(b) Effective on the date ~~Portland~~ of any sale outside the Pacific Northwest of a resource now dedicated to serve Portland's load in Portland's Power Sales Contract Firm Resource Exhibit, Portland shall submit a revised Firm Resources Exhibit and Assured Capability Exhibit to Bonneville under the Power Sales Contract. The Firm Resource Exhibit shall include, as a Firm Resource, Portland's obligation to provide during each calendar month, an amount of energy equal to the maximum amount of energy Portland is obligated to provide during each such month for use outside of the Pacific Northwest. The determination of Portland's Assured Energy Capability under the Assured Capability Exhibit shall include the monthly amounts of energy from such Firm Resource.

(c) If Portland fails to comply with the terms and conditions of this section, then Bonneville shall have the right to terminate this agreement.

(VS6-PMT-2692d)

Northwest AC Intertie Losses

Portland's 500-kV Grizzly-Malin line will be placed in Bonneville's generation control area and Bonneville shall absorb all losses on the line. Portland shall compensate Bonneville for Northwest AC Intertie losses by making available to Bonneville at points-of-delivery as included in the terms and provisions of Portland's transmission agreements with Bonneville for service over the FCRTS, at the corresponding hour 168 hours later, an amount of electric power calculated as follows:

Given:

Average Northwest AC Intertie losses are 3.0%

Portland can deliver a portion of its schedules through Grizzly Substation, as provided in §8(d)(2), reducing its average loss percentage to 2.5%

For a given hour:

S_{PGE} = Portland's net Northwest AC Intertie schedule, found as the absolute value of the sum of Portland's southbound schedules (positive) and northbound schedules (negative).

L_{PGE} = Portland's loss

Let:

$$L_{PGE} = 0.025 * S_{PGE}$$

This Exhibit E will become effective 90 days after the Effective Date.

The average Northwest AC Intertie loss percentage specified above shall be reviewed annually, and revised as mutually agreed by the parties.

(VS6-PMT-2692d)

Calculation of Charges for Access to Southern Oregon (SO) Substation
1988 ($)

Item No. 1/	Description	2/ Investment	Annual Cost Ratio 3/	Subtotal	O&M Cost 4/	Grand Total
1.	Malin-Meridian Loop into SO 5/	904,000	0.1150	103,960	0 6/	103,960
2.	Grizzly-Malin Loop into SO	4,186,000	0.1150	481,390	3,582	484,972
3.	SO -Or/CA Border	5,265,000	0.1150	605,475	7,164	612,639
4.	SO PCB's, Comm. & Controls 7/	17,621,000	0.1170	2,061,657	282,300	2,343,957
5.	SO Capacitors (10%) 8/	669,000	0.1170	78,273	38,606	116,879
	TOTAL					$3,662,407

PGE Annual Charge = (950 / 4800) * $3,662,407 = $724,852 / YR

1/ BPA's share of Northwest Reinforcement facilities. PP&L's solely owned facilities are not included.
2/ Investment costs include 30% overheads. This column will be revised to reflect actual construction costs.
3/ BPA's Annual Cost Ratio represents recovery of BPA's plant investment costs, revised at time of construction and fixed for the duration of the agreement. When any of the facilities in the table above are replaced or enhanced, PGE shall pay 950/4800 of the associated annual costs, less retirements. Payment schedule for I&A ends, if facilities still exist and are not enchanced or replaced at the end of the service life specified in BPA's Annual Cost Ratio Tables.
4/ BPA's O&M dollars shown for Items 2, 3, 4 and 5 are based on O&M expenses averaged for FY 1985, '86, and '87. O&M charges will be reviewed annually and revised, as appropriate.
5/ BPA's share of the Malin-Meridian Loop-in costs is 50% and PP&L's share is 50%.
6/ PP&L is to operate and maintain the Malin-Meridian Line.
7/ BPA's share is assumed at 6/7th and PP&L's share is 1/7th of $20,558,000.
8/ BPA's share is assumed at 10% and COTP's share is 90% of $6,689,000.

(VS6-PMT-2692d)

Calculation of DC Intertie Losses

The loss factor to be applied to the energy delivered by Bonneville for Portland over the DC Intertie shall be 3.0 percent. Such loss factor shall be reviewed yearly, and revised if appropriate.

(VS6-PMT-2692d)

AUTHENTICATED COPY

Contract No. DE-MS79-91BP93094
7/12/91

INTERTIE TRANSMISSION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

IDAHO POWER COMPANY

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This INTERTIE TRANSMISSION AGREEMENT, executed July 25, 1991, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and IDAHO POWER COMPANY (Company), a corporation of the State of Idaho, hereinafter sometimes referred to individually as "Party" and collectively as "Parties."

W I T N E S S E T H :

WHEREAS Bonneville and the Company, on August 27, 1982, entered into Contract No. DE-MS79-81BP90422, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract"; and

WHEREAS the Company and the Cities of Azusa, California, Banning, California, and Colton, California (Cities), on December 26, 1990, entered into a Power Sale Agreement which, as amended or replaced, is hereinafter referred to as "Sales Agreement"; and

WHEREAS the Sales Agreement provides for the sale of Electric Power by the Company to the Cities; and

WHEREAS Bonneville has developed the LTIAP, which includes provisions for non-Federal access to the Intertie for Assured Delivery to California entities; and

WHEREAS the Company desires transmission service over the Direct Current (DC) Intertie for the transmission of Electric Power to be provided by the Company to the Cities in accordance with the Sales Agreement; and

WHEREAS the Company and Bonneville desire to provide for such DC Intertie transmission service pursuant to the terms of this Agreement and to the terms of the LTIAP; and

WHEREAS the Parties have entered into a General Transmission Agreement, Contract No. DE-MS79-91BP92898 which, as amended or replaced, is hereinafter referred to as "IR Transmission Agreement"; and

WHEREAS Bonneville shall provide for the transmission of Electric Power from a point of integration under the IR Transmission Agreement to the Government's Big Eddy Substation; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto mutually agree as follows:

1. Term of Agreement. This Agreement shall be effective on the Effective Date, and shall continue in effect until the earlier of (1) 20 years from the Effective Date; or (2) the termination date of the Sales Agreement; provided, however, that all liabilities incurred hereunder are hereby preserved until satisfied.

2. Definition and Explanation of Terms.

(a) "Agency" means the Federal Energy Regulatory Commission, or its successor agency.

(b) "Agreement" means this Intertie Transmission Agreement, Contract No. DE-MS79-91BP93094.

(c) "Assured Delivery" is as defined in the LTIAP.

(d) "DC Intertie" means Bonneville's rights in the 1000 kV DC transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to NOB.

(e) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system related to the disturbances of concern, thereby providing acceptable power system performance.

(f) "Effective Date" means the later of (1) 2400 hours on the effective date of the Sales Agreement; (2) 2400 hours on the effective date of the IR Transmission Agreement; or (3) 2400 hours on the date of execution of this Agreement.

(g) "Electric Energy" means electric energy, expressed in kilowatthours.

(h) "Electric Power" or "power" means electric capacity, expressed in kilowatts (kW), or Electric Energy, or both.

(i) "Formula Allocation" is as defined in the LTIAP.

(j) "Intertie" means the DC Intertie and Bonneville's portion of the two 500 kV alternating current (AC) transmission lines from the Government's John Day substation to the California-Oregon border, and associated substation facilities; a portion of the Buckley-Summer Lake 500 kV transmission line and Bonneville's rights in the Summer Lake-Malin 500 kV line; and expansions, improvements, and additions to such transmission lines and substations, including the proposed Northwest Reinforcement Project to the extent such

project is constructed and the third 500 kV AC transmission line interconnecting the Pacific Northwest and California is made operable.

(k) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, attached hereto as Exhibit E.

(l) "Network" means the facilities of the Federal Columbia River Transmission System utilized for the transmission of Electric Power from the Company's transmission system to the Government's Big Eddy Substation.

(m) "NOB" means the Nevada-Oregon border and the point of delivery at such point as described in Exhibit C.

(n) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency or loading condition on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce DC Intertie loadings, whether or not all facilities are in service.

(o) "Pacific Northwest" means the area of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five (75) miles from the area referred to above, which are a part of the service area of a rural electric cooperative customer served by Bonneville on the effective date of Public Law 96-501, which has a distribution system from which it serves both within and without such region.

(p) "Pacific Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act.

(q) "Point of Interconnection" means the Government's Big Eddy Substation, as described in Exhibit C, where Electric Power shall be made available to Bonneville for transmission over the DC Intertie hereunder.

(r) "Prudent Utility Practice" means at any particular time, the generally accepted practices, methods, and acts in the electrical utility industry in the Western Systems Coordinating Council area prior thereto or, if there are no such practices, methods or acts, the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(s) "Rated Transfer Capability" means the capability of a transmission line or system to transfer Electric Power in a reliable manner as determined in accordance with Prudent Utility Practice.

(t) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville powerflows and/or stability studies.

(u) "Transmission Demand" means the maximum firm DC Intertie transmission capacity, as specified in Exhibit C, for each month, that Bonneville shall be obligated to make available to the Company for transmission of Electric Power under the terms of this Agreement.

(v) "Workday" means each day that Bonneville and the Company jointly observe as a regular workday.

3. Exhibits and Interpretations. The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and

governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement, which represents the entire agreement between the Parties. The headings used in this contract are for convenient reference only, and shall not affect the interpretation of this Agreement. The Company shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. Transmission of Electric Power. Subject to the provisions of this Agreement, the Company shall arrange to make available to Bonneville at the Point of Interconnection, pursuant to the IR Transmission Agreement, the amounts of Electric Power that the Company desires to have transmitted for each hour hereunder, from north to south, over the DC Intertie. Bonneville shall, for each such hour, make equal amounts of Electric Power available for the Company at NOB.

(a) The maximum amount of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand.

(b) The Electric Power transmitted hereunder shall, for the term of this Agreement, reduce the Company's available reserved capacity under Exhibit B of the LTIAP by the amount of the Transmission Demand in this Agreement. The Company shall use its allocation under the LTIAP Formula Allocation methodology for the transmission of the Assured Delivery amount under this Agreement prior to scheduling non-Assured Delivery sales over the Intertie.

(c) During hours when the Rated Transfer Capability of the DC Intertie is reduced due to system conditions, Bonneville shall be obligated to deliver

Electric Power, pursuant to this Agreement, to the extent the Cities and the Company can accept or deliver such Electric Power, up to the Cities' share of reduced Rated Transfer Capability.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints. The amount of curtailment shall be determined consistent with Prudent Utility Practice.

(e) This subsection applies to this Agreement in the event the Company's Transmission Demand, including any shaping under the LTIAP and including transmission demands in other agreements pursuant to which Bonneville provides Intertie transmission to the Company, is equal to or greater than 100 MW. The Company shall, if requested by Bonneville, participate in Intertie Remedial Action Schemes. Bonneville and the Company shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. The Company may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective Control Action is obtained. The level of reliability of the Remedial Action Scheme design on the Company's system shall be at least equal to the level of reliability employed in the design of the overall Intertie Remedial Action Scheme.

(1) The Company's contribution to the total operational responsibility for this scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the Rated Transfer Capability of the Intertie prior to any reduction thereof due to such electrical disturbances.

(2) Bonneville shall provide the appropriate control signal or signals to the Company.

(3) The Company shall provide the necessary equipment to receive and transmit the control signal or signals to the Company's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions.

5. Mitigation Provisions. The Company shall be subject to the operational mitigation provisions of Section 4(d) of the LTIAP as follows:

(a) Condition 1 Provisions.

(1) During hours hereunder when Bonneville has invoked Condition 1 as specified in Section 5(c)(1) or 5(d)(1) of the LTIAP, and the Company's Formula Allocation for such an hour is less than the Company's Assured Delivery, the Company shall purchase the Electric Power difference for delivery to the Cities either from Bonneville, in the event Bonneville has Formula Allocation available for such purpose, or from any other Scheduling Utilities which have Formula Allocation and Electric Power available for such purpose.

(2) The Company shall pay Bonneville each month for the Electric Power purchased by the Company from Bonneville pursuant to (1) above, based upon, at Bonneville's option, (i) Bonneville's standard nonfirm rate, NF-89 or its successor, for sales to California entities, which is determined by Bonneville to best reflect the market conditions in existence on the day Bonneville provides such Electric Power; or (ii) Bonneville's surplus firm rate or at another rate mutually agreed upon by the Company and Bonneville.

(b) Condition 2 Provisions.

(1) During hours hereunder when Bonneville has invoked Condition 2 as specified in Section 5(c)(2) or 5(d)(2) of the LTIAP, and the Company's Formula Allocation for such hours, or for the purposes of Section 5(d)(2) of the LTIAP the Formula Allocation the Company would have otherwise received for such hour if Section 5(c)(2) of the LTIAP were in effect, is less than the Company's Assured Delivery, the Company shall purchase the Electric Power difference from Bonneville, for delivery to the Cities, in the event Bonneville has Formula Allocation available for such purpose.

(2) In the event Bonneville does not have Formula Allocation available for such purpose, the Company may purchase the Electric Power difference from any other Scheduling Utility with available Formula Allocation.

(3) The Company shall pay Bonneville each month for the Electric Power purchased by the Company from Bonneville pursuant to paragraph 5(b)(1) above, based upon, at Bonneville's option, (i) Bonneville's standard nonfirm rate, NF-89 or its successor, for sales to California entities, which is determined by Bonneville to best reflect the market conditions in existence on the day Bonneville provides such Electric Power; or (ii) Bonneville's surplus firm rate or at another rate mutually agreed upon by the Company and Bonneville.

(c) Should Bonneville revise its procedures for administering Operational Mitigation measures included in Assured Delivery contracts entered into pursuant to Exhibit B of the LTIAP, Bonneville agrees to discuss such revisions with the Company. If they so desire, the Parties may amend this

Agreement to prospectively incorporate such revised procedures or such other procedures as may be agreeable to both Parties.

6. Payment Provisions. As compensation for the Intertie transmission services provided to the Company by Bonneville in accordance with section 4 above, the Company shall pay Bonneville each month, in accordance with the provisions of Exhibits B and C, an amount equal to the products obtained by multiplying the Transmission Demand and the amounts of Electric Energy transmitted by Bonneville hereunder by the demand and energy charges, respectively, specified in the Firm Power Transmission Rate included in Transmission Rate Schedule IS-89 (IS-89B rate), or its successor rates. Such amounts of Electric Energy shall be increased by the amount calculated in accordance with the transmission loss factor specified in Exhibit D.

7. Transmission Losses. To compensate Bonneville for Electric Power losses incurred in providing services from the Point of Interconnection to NOB, the Company shall make available, or arrange to have made available, to Bonneville at NOB, unless otherwise mutually agreed upon by the Parties, at the corresponding hour 168 hours later or at another hour agreed upon by the Parties, the amounts of Electric Power determined pursuant to Exhibit D.

8. Power Scheduling. Pursuant to standard scheduling practices, the Company shall submit, or arrange to have submitted, to Bonneville by 0930 hours Pacific Time on each Workday:

(a) A schedule in advance of Electric Power to be supplied to Bonneville for each hour of the following day or days;

(b) A schedule in advance of Electric Power to be supplied to the Company from Bonneville pursuant to section 5 above; and

(c) separate schedules of the hourly amounts of Electric Power to be made available pursuant to section 7 for transmission losses for each hour of the following day or days.

9. Revision of Exhibits.

(a) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of Section 7(i) of the Pacific Northwest Power Act (P.L. 96-501, 16 U.S.C. 839) and Agency rules.

(b) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then-current Intertie operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, that has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with the Company. Losses shall be determined and applied to the Company's transactions under this Agreement in a manner consistent with their application to all similarly situated users of the Intertie having a similar contract with Bonneville as determined by Bonneville. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(c) If Bonneville determines that any charge or parameter specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate, incorporating such revised charges and parameters. Such new exhibit shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(d) Any changes to Exhibit C pursuant to this Agreement shall be upon mutual agreement of the Parties. Upon such mutual agreement, Bonneville shall prepare and issue a revised Exhibit C.

10. Waiver of Bonneville's Energy Service Obligation.

(a) The Company agrees that the disposition of Electric Energy for use outside of the Pacific Northwest pursuant to the Sales Agreement shall result in a reduction of Bonneville's obligation to the Company under section 5(b) of the Northwest Power Act. Bonneville's obligation to supply firm power under the Power Sales Contract, as amended or replaced, shall be reduced on the effective date of a written notice from Bonneville by the maximum amount of Electric Energy which the Company is obligated to provide for use outside of the Pacific Northwest pursuant to the Sales Agreement. Bonneville shall implement such reduction as described in subsection (b) below.

(b) The Company shall submit to Bonneville a revised Firm Resources Exhibit and associated data as specified under the Power Sales Contract effective on the effective date of the notice pursuant to subsection (a) above. The Firm Resources Exhibit shall include, as a Firm Resource, the amount of the Company's obligation to provide Electric Energy for use outside of the Pacific Northwest pursuant to the Sales Agreement.

11. Compliance With Long-Term Intertie Access Policy. Except as otherwise specified in this Agreement, transmission service provided by Bonneville to the Company over the DC Intertie hereunder shall be subject to the terms of the LTIAP. The terms of this Agreement shall not be subject to change upon amendment of the LTIAP, except by mutual agreement of the Parties;

provided, however, Bonneville may unilaterally change the Protected Areas in Exhibit C to the LTIAP to apply such changes to generation resources which have not been licensed by the Agency.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ Walter E. Pollock

By _____
Assistant Administrator
for Power Sales

IDAHO POWER COMPANY

By _____ /s/ J. B. Packwood

Title Vice President Vice President

Date July 16, 1991 July 16, 1991

(VS6-PMT-3405e)

Transmission Parameters

A. Transmission Demand.

7,000 kW

B. Description of NOB and BIG EDDY.

1. NOB POINT OF DELIVERY:

Location: the point in the DC Intertie, near the Nevada-Oregon border, where Bonneville shall make Electric Power available for the Company hereunder;

Voltage: 1000 kV.

2. BIG EDDY POINT OF INTERCONNECTION:

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus;

Voltage: 230 kV and 500 kV.

Transmission Loss Factor

A. Transmission Loss Factor to be Applied to Transmission Pursuant to the Southern Intertie Transmission (IS) Rate Schedule.

Rate Schedule	Loss Factor
IS-89	3.0%

AUTHENTICATED

This Revision No. 2 reduces the Transmission Demand from 4,000 kW to 3,000 kW due to the buyout arrangement of the Power Sales Agreement between Idaho Power Company and the City of Banning, California. The filing of the terms and conditions of this buyout with the Federal Energy Regulatory Commission has been accepted under Docket No. ER98-754-000.

TRANSMISSION PARAMETERS

1. TRANSMISSION DEMAND
3,000 kW

2. POINTS OF DELIVERY AND INTERCONNECTION

a.. Nevada-Oregon Border (NOB) Point of Delivery

Location. The point in the DC Intertie, near the Nevada-Oregon border, where the facilities of the Government and the facilities of the Los Angeles Department of Water and Power interconnect

Voltage. 1000 kV

b. Big Eddy Point of Interconnection

Location. The point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus

Voltage. 230 kV and 500 kV

IDAHO POWER COMPANY

By: /S/ AJAY K. SOOD

Name: Ajay K. Sood

Title: Director, Energy Analysis & Power Transmission

Date: March 4, 1998

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ SUSAN E. GARIFO FURST

Name: Susan E. Garifo Furst

Title: Transmission Account Executive

Date: 12 February 1998

AUTHENTICATED COPY

Contract No. DE-MS79-94BP94280
05/26/94

DC INTERTIE AND NETWORK TRANSMISSION AGREEMENT executed by the UNITED STATES OF AMERICA DEPARTMENT OF ENERGY acting by and through the BONNEVILLE POWER ADMINISTRATION and PACIFICORP

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This DC INTERTIE AND NETWORK TRANSMISSION AGREEMENT, executed June 1, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon (hereinafter referred to individually as "Party" and collectively as "Parties").

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WITNESSETH:

WHEREAS Bonneville and PacifiCorp, on August 27, 1982, entered into Contract No. DE-MS79-81BP90424, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract; and

WHEREAS Bonneville and PacifiCorp have entered into a Letter of Understanding (LOU) dated May 28, 1993, which provides that, among other things, Bonneville shall offer PacifiCorp a firm South-to-North transmission agreement for use of the DC Intertie and Network transmission service associated with PacifiCorp's use of the DC Intertie; and

WHEREAS Bonneville and PacifiCorp entered into an AC Intertie Agreement, Contract No. DE-MS79-94BP94332, which, as amended or replaced, is hereinafter referred to as "AC Intertie Agreement." The AC Intertie Agreement replaced the Intertie Agreement, Contract No. DE-MS79-86BP92299; and

WHEREAS Bonneville desires to provide PacifiCorp DC Intertie transmission service and Network transmission service associated with such DC Intertie transmission service, pursuant to paragraphs 4(a) and (c) of the LOU and the terms of this Agreement; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the Parties hereto mutually agree as follows:

1. **TERM OF AGREEMENT**

This Agreement shall be effective on the Effective Date, and shall continue in effect until termination of the AC Intertie Agreement; provided, however, that all liabilities incurred hereunder are hereby preserved until satisfied.

2. DEFINITION AND EXPLANATION OF TERMS

(a) "AC Intertie" means Bonneville's rights in the following: the two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line; Bonneville's rights in the Meridian-Malin 500 kV transmission line; Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the ten kilometer (6-mile) 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, improvements, or additions to such facilities.

(b) "Agreement" means this DC Intertie and Network Transmission Agreement, Contract No. DE-MS79-94BP94280.

(c) "Billing Energy" means the monthly sum of scheduled Electric Energy hereunder.

(d) "DC Intertie" means Bonneville's rights in the 1000 kV direct current (DC) transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to NOB.

(e) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system related to the disturbances of concern, thereby providing acceptable power system performance.

(f) "Effective Date" means 2400 hours on the date of execution of this Agreement.

(g) "Electric Energy" means electric energy, expressed in kilowatt-hours.

(h) "Electric Power" or "power" means electric capacity, expressed in kilowatts (kW), or Electric Energy, or both.

(i) "FERC" means the Federal Energy Regulatory Commission, or its successor agency.

(j) "Intertie Transmission Charges" means the Demand Charge and Energy Charge specified in Section II.B. of the Southern Intertie Transmission Rate Schedule (IS) or its successor rate schedules, and included as part of Exhibit B, for DC Intertie transmission service provided hereunder.

(k) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, and amended on April 8, 1993.

(l) "Network" means the facilities of the Federal Columbia River Transmission System utilized hereunder, excluding the AC Intertie and the DC Intertie facilities, for the transmission of Electric Power from the Government's Big Eddy Substation to the Point of Delivery as described in Exhibit C.

(m) "Network Transmission Charge" means the charge specified in Exhibit C and calculated pursuant to the Formula Power Transmission (FPT) Rate Schedule or its successor rate schedules, which is the monthly charge per kilowatt of Transmission Demand for Network transmission service provided hereunder.

(n) "NOB" means the Nevada-Oregon border and the Point of Interconnection as described in Exhibit C.

(o) "Operational Transfer Capability" or "OTC" means the Rated Transfer Capability less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, and Operational Constraints, as determined by Bonneville, resulting from, among other things, line or equipment outages, stability limits, or loopflows.

(p) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency, loading condition, or maintenance outage on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce DC Intertie loadings, whether or not all facilities are in service.

(q) "Pacific Northwest" is as defined in the LTIAP.

(r) "Pacific Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act.

(s) "Prudent Utility Practice" means at any particular time, the generally accepted practices, methods, and acts prior thereto in the electrical utility industry in the Western Systems Coordinating Council area or, if there are no such practices, methods or acts, the practices, methods or acts, which, in the exercise of reasonable judgment in the light of facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(t) "Rated Transfer Capability" or "RTC" means the capability of a transmission line or system to transfer a specified quantity of Electric Power in a prudent and reliable manner.

(u) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville powerflows and/or stability studies.

(v) "Transmission Demand" means the maximum amount of Electric Power that Bonneville shall be obligated to transmit during an hour hereunder. Such amount is specified in Exhibit C and shall be changed only upon mutual agreement of the Parties.

(w) "Workday" means each day that Bonneville and PacifiCorp jointly observe as a regular workday.

3. **EXHIBITS AND INTERPRETATIONS**

The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement. This Agreement sets forth the entire agreement of the Parties as of the date of execution. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement. PacifiCorp shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. **TRANSMISSION OF ELECTRIC POWER**

Subject to the other provisions of this Agreement, Electric Power shall be transmitted on a firm basis from South-to-North, over the DC Intertie from the NOB Point of Interconnection to the Government's Big Eddy Substation (Big Eddy) and over the Network from Big Eddy to the Network Point of Delivery specified in Exhibit C as follows:

(a) The maximum hourly amount of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand.

(b) During hours when the OTC of the DC Intertie is less than the RTC, Bonneville shall deliver Electric Power pursuant to this Agreement to PacifiCorp, to the extent PacifiCorp can accept or deliver such Electric Power, up to PacifiCorp's transmission rights hereunder.

(c) This subsection applies to this Agreement in the event PacifiCorp's Transmission Demand, including transmission demands in other agreements pursuant to which Bonneville provides DC Intertie transmission service to PacifiCorp, is equal to or greater than 100 MW. PacifiCorp shall, if requested by Bonneville, participate in DC Intertie Remedial Action Schemes. Bonneville and PacifiCorp shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. PacifiCorp may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective

Control Action is obtained. The level of reliability of the Remedial Action Scheme design on PacifiCorp's system shall be at least equal to the level of reliability employed in the design of the overall DC Intertie Remedial Action Scheme.

(1) PacifiCorp's contribution to the total operational responsibility for this scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the RTC of the DC Intertie prior to any reduction thereof due to such electrical disturbances.

(2) Bonneville shall provide the appropriate control signal or signals to PacifiCorp.

(3) PacifiCorp shall provide the necessary equipment to receive and transmit the control signal or signals to PacifiCorp's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints, consistent with Prudent Utility Practice, and up to an amount equal to PacifiCorp's transmission rights, such rights to be determined as the amount obtained from the product of the OTC and the ratio of the Transmission Demand to the RTC.

(e) During times when PacifiCorp's transmission rights hereunder are curtailed, Bonneville shall offer available DC Intertie capacity as determined by Bonneville, to PacifiCorp, up to the amount of such curtailment, pursuant to the terms of this Agreement.

5. PAYMENT PROVISIONS

(a) As compensation for the Network transmission services provided hereunder, PacifiCorp shall pay Bonneville in accordance with the provisions of Exhibits B and C for each month, an amount equal to the product obtained by multiplying the Transmission Demand by the Network Transmission Charge specified in Exhibit C.

(b) As compensation for the DC Intertie transmission services provided hereunder, PacifiCorp shall pay Bonneville in accordance with the provisions of Exhibits B and C each month, (1) an amount equal to the product obtained by multiplying the Transmission Demand by the Demand Charge of the Intertie Transmission Charges and (2) the greater of (a) the product obtained by multiplying the Billing Energy by the Energy Charge of the Intertie Transmission Charges or (b) the minimum payment based upon the Energy Charge and a 30 percent load factor. Such minimum energy payment shall be calculated as follows: Transmission Demand (MW) x 8760 hours x Energy Charge (mills/kWh) x .30 ÷ 12.

6. TRANSMISSION LOSSES

To compensate Bonneville for Electric Power losses incurred in providing the services hereunder, PacifiCorp shall schedule and make available to Bonneville on the corresponding hour 168 hours later or on another hour agreed upon at the Network Point of Delivery, the amounts of Electric Power calculated in accordance with the Loss Factors specified in Parts A and B of Exhibit D.

7. POWER SCHEDULING

Pursuant to standard scheduling practices, PacifiCorp shall submit, or arrange to have submitted, to Bonneville by 0930 hours Pacific Time on each Workday or such other time as mutually agreed by the Parties:

(a) A schedule for South-to-North transfers of Electric Power to be made available to Bonneville at NOB for each hour of the following day or days through the next Workday. Changes to such schedules by PacifiCorp shall be accepted up to 30 minutes prior to the hour for which such schedules change is desired; and

(b) a separate schedule of the hourly amounts of Electric Power to be made available pursuant to section 6 for transmission losses for each hour of the following day or days through the next Workday.

(c) Changes to schedules other than those permitted pursuant to 7(a) shall be accepted at any time as mutually agreed by the Parties.

8. REVISION OF EXHIBITS

(a) The initial rate schedules attached hereto as Exhibit B have been confirmed and approved by FERC on an interim basis. If the final rate schedules which are approved by FERC are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated General Transmission Rate Schedule Provisions shall be attached hereto and made a part of this Agreement effective as of the date specified in FERC's approval.

(b) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of Section 7(i) of the Pacific Northwest Power Act and FERC rules.

(c) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then-current AC Intertie and DC Intertie and Network operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, that has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with PacifiCorp. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that any charge specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate, incorporating such revised charges. Such new exhibit

shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(e) If the Parties agree to change Exhibit C pursuant to this Agreement, Bonneville shall prepare and issue a revised Exhibit C.

9. MITIGATION

Pursuant to the Letter of Understanding, dated May 28, 1993, the Parties agree that no LTIAP mitigation shall be applicable under this Agreement, beyond the applicable FERC-approved Bonneville rates.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

/s/ SYDNEY D. BERWAGER (acting)
Assistant Administrator
for Power Sales

By ACTING Assistant Administrator for
Power Sales

Name Sydney D. Berwager
(Print/Type)

May 26, 1994

Date 5/26/94

PACIFICORP

By

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date June 1, 1994

/s/ DENNIS P. STEINBERG

Senior Vice President

June 1, 1994

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GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. Reducing Charges for Interruptions. If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{/(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load-factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

TRANSMISSION PARAMETERS

A. TRANSMISSION DEMAND

(1) 100 MW, effective the later of 0001 hours on January 1, 1994, or 2400 hours on the date of execution of this Agreement.

(2) 200 MW, effective 0001 hours on January 1, 1995.

B. DESCRIPTION OF THE DC INTERTIE POINT OF INTERCONNECTION

NOB:

Location: the point in the DC Intertie, near the Nevada-Oregon border, where Electric Power shall be made available to Bonneville on behalf of PacifiCorp;

Voltage: 1000 kV.

C. DESCRIPTION OF THE BIG EDDY SUBSTATION

BIG EDDY SUBSTATION:

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus;

Voltage: 230 kV and 500 kV.

D. DESCRIPTION OF THE NETWORK POINT OF DELIVERY

BUCKLEY SUBSTATION:

Location: the point in the Government's Buckley Substation at the northern terminus of the Buckley-Summer Lake 500 kV line;

Voltage: 500 kV;

Metering: in the Government's Buckley Substation, in the circuits over which such electric power and energy is delivered.

NETWORK TRANSMISSION CHARGE

E. CALCULATION OF CHARGES PURSUANT TO THE FPT-93.1 RATE SCHEDULE

	Schedule of Annual Charges per kW	Applicable Annual Charges per kW from Big Eddy to Buckley (500 kV)
Facility		
Main Grid		
Interconnection Terminal	$0.27	--
Terminal	$0.44	$0.44
Transmission Distance Charge (1.15 x $0.0371/miles x 44.16 kilometers (27.6 airline miles)	$0.0371/ 1.6 kilometer (1 mile)	$1.18
Miscellaneous Facilities	$1.88	$1.88
Terminal	$0.44	--1/
Interconnection Terminal	$0.27	--
Total Annual Charge $/kW/yr.		$3.50
Transmission Charge $/kW/mo.		$0.29

1/ See Contract No. DE-MS79-79BP90091 and its successor Contract No. DE-MS79-94BP94333 for PacifiCorp's right to use the Government's initial terminal facilities in the Buckley Substation.

TRANSMISSION LOSS FACTORS

A. TRANSMISSION LOSS FACTOR TO BE APPLIED TO TRANSMISSION PURSUANT TO THE FORMULA POWER TRANSMISSION (FPT) RATE SCHEDULE:

Rate Schedule	Loss Factor
FPT-93.1	See Exhibit E, Calculation of Hourly Losses.

B. TRANSMISSION LOSS FACTOR TO BE APPLIED TO TRANSMISSION PURSUANT TO THE SOUTHERN INTERTIE TRANSMISSION (IS) RATE SCHEDULE:

Rate Schedule	Loss Factor
IS-93B	3.0%

CALCULATION OF HOURLY LOSSES

Assume:

Lp = Peak wheeling loss applicable to a specified peak amount of power wheeled under this agreement during the time of peak Federal system generation. Lp is a constant for each hour of a billing period.

Dm = Airline transmission distance plus 15 percent.

Ds = Secondary system transmission distance.

Wm = Maximum power wheeled over main system under this transmission agreement.

Ws = Maximum power wheeled over secondary system under this transmission agreement.

Wt = Maximum power wheeled through the stepdown transformations under this transmission agreement.

Lm = Average loss per megawatt-mile on the main system. Lm is constant for each hour of a billing period.

Ls = Average loss per megawatt-mile on the secondary system. Ls is a constant for each hour of a billing period.

Lt = 230/115 kV transformation loss (percent).

Lt1 = Weighted average of the 115 kV transformation loss (percent).

Lw = Wheeling loss for the power scheduled for a particular hour under this transmission agreement.

Pf = Federal generation for a particular hour.

Pfp = Amount of Federal generation upon which the average wheeling loss, Lm, was based. Pfp is constant for each hour of a billing period.

Pw = Amount of power scheduled for a particular hour to be wheeled under this agreement by Bonneville.

Peak Loss Calculation:

$$\begin{aligned} Lp &= (Dm)(Wm)(Lm) + (Wt)(Lt) + (Ds)(Ws)(Ls) + (Wt)(Lt1) \\ &= (31.74)(100\ MW)(0.143) \\ &= 454\ kW\ per\ MW \end{aligned}$$

Hourly Wheeling Loss Calculation:

$$Lw = \frac{(Lp)(Pf)(Pw)}{(Pfp)(Wm)}$$

$$Let\ K = \frac{Lp}{(Pfp)(Wm)}$$

$$= \frac{454}{(16{,}221{,}000)(100{,}000)}$$

$$= 0.28 \times 10^{-9}/kW = 0.28 \times 10^{-6}/MW$$

Therefore,

$$\begin{aligned} Lw &= K(Pf)(Pw) \\ &= (0.28 \times 10^{-6})\,(Pf)(Pw)/MW \end{aligned}$$

Hourly losses are determined by inserting the amounts of Pf and Pw for a particular hour.

Final Document Certified By:

CCP
94BP94280

Date: 9-30-03
on

Revision No. 4
Exhibit C, Page 1 of 2
Contract No. DE-MS79-

PacifiCorp
Effective as of 0000 Hours

October 1, 2003

AUTHENTICATED

CHARGES, DEMAND, AND POINTS OF DELIVERY

This revision updates the Transmission and Compensation charges with the new Formula Power Transmission Rate Schedule, FPT-04.1, effective October 1, 2003.

A. TRANSMISSION DEMAND

200 MW, effective 0001 hours on January 1, 1995.

B. DESCRIPTION OF THE DC INTERTIE POINT OF INTERCONNECTION

Nevada-Oregon Border

Location: the point in the DC Intertie, near the Nevada-Oregon border, where Electric Power shall be made available to the Bonneville Power Administration (Bonneville) on behalf of PacifiCorp;

Voltage: 1000 kilovolt (kV).

C. DESCRIPTION OF THE BIG EDDY SUBSTATION

Big Eddy Substation

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 230 kV bus and the 500 kV bus;

Voltage: 230 kV and 500 kV.

D. DESCRIPTION OF THE NETWORK POINT OF DELIVERY

Buckley Substation

Location: the point in the Government's Buckley Substation at the northern terminus of the Buckley-Summer Lake 500 kV line;

Voltage: 500 kV;

Metering: in the Government's Buckley Substation, in the circuits over which such Electric Power and energy is delivered.

NETWORK TRANSMISSION CHARGE

E. CALCULATION OF CHARGES PURSUANT TO THE FPT-04.1 RATE SCHEDULE

Facility	Schedule of Annual Charges ($/kilowatt (kW))	Applicable Annual Charges from Big Eddy to Buckley 500 kV ($/kW)
Main Grid		
Interconnection Terminal	0.53	
Terminal	0.59	.59
Transmission Distance Charge (1.15 × 0.0511/mile × 27.6 airline miles)	0.0511/mi.	1.622
Miscellaneous Facilities	2.91	2.91
Terminal	0.59	*/
Interconnection Terminal	0.53	
Total Annual Charge ($/kW/yr)		**5.122**
Transmission Charge ($/kW/mo)		**0.427**

*/ See Contract No. DE-MS79-79BP90091 and its successor Contract No. DE-MS79-94BP94333 for PacifiCorp's right to use the Government's initial terminal facilities in the Buckley Substation.

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Contract No. DE-MS79-94BP94285
05/25/94

AC INTERTIE TRANSMISSION AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP

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This AC INTERTIE TRANSMISSION AGREEMENT, executed June 1, 1994, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and PACIFICORP (PacifiCorp), a corporation organized and existing under the laws of the State of Oregon, (hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS Bonneville and PacifiCorp, on August 27, 1982, entered into Contract No. DE-MS79-81BP90424, which, as amended or replaced, is hereinafter referred to as "Power Sales Contract"; and

WHEREAS PacifiCorp and the Western Area Power Administration Sacramento Area Office (Western) have entered into a contract dated September 17, 1992, which, as amended or replaced, is hereinafter referred to as "Western Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to Western; and

WHEREAS PacifiCorp and the City of Redding (Redding) have entered into a contract dated October 19, 1993, which, as amended or replaced, is hereinafter referred to as "Redding Sales Agreement", which provides for the sale of Electric Power from PacifiCorp to the City of Redding; and

WHEREAS Bonneville and PacifiCorp entered into an Intertie Agreement, Contract No. DE-MS79-86BP92299, as amended, effective July 8, 1986, which is hereinafter referred to as " Intertie Agreement", and the Parties have replaced such agreement with Contract No. DE-MS79-94BP94332, which, as amended or replaced, is hereinafter referred to as "AC Intertie Agreement"; and

WHEREAS Bonneville and PacifiCorp have entered into a Letter of Understanding (LOU) dated May 28, 1993, which provides that Bonneville shall under certain circumstances offer PacifiCorp interim and long-term firm transmission contracts providing wheeling for PacifiCorp's Western Sales Agreement and Redding Sales Agreement, and for nonfirm wheeling; and

WHEREAS Bonneville has developed the LTIAP, as defined below, which includes provisions for non-Federal access to the AC Intertie for transactions with Pacific Northwest and California utilities; and

WHEREAS the Parties agree that the terms and conditions of the LOU represent a Joint Venture pursuant to Section 4(b)(1) of the LTIAP; and

WHEREAS consistent with the LOU and in order to facilitate the arrangements provided for in the Western Sales Agreement and the Redding Sales Agreement, Bonneville will provide transmission service in a North-to-South direction from the Points of Interconnection, over the AC Intertie, for deliveries of Electric Power to Western, Redding, and other third parties at the Points of Delivery, and transmission service in a South-to-North direction from the Points of Interconnection, over the AC Intertie, to the Points of Delivery for the delivery of Electric Power to PacifiCorp; and

WHEREAS in accordance with the LOU, Bonneville will provide such access to the AC Intertie for firm and nonfirm transactions up to the Transmission Demand both in a North-to-South and South-to-North direction without regard to the source or ultimate user of services provided under such transactions; and

WHEREAS PacifiCorp and Bonneville desire to provide for such services pursuant to the terms of this Agreement and pursuant to the terms of the LTIAP; and

WHEREAS Bonneville is authorized pursuant to law to dispose of Electric Power generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. TERM OF AGREEMENT

This Agreement shall be effective on the Effective Date, and shall continue in effect until the earlier of (1) 2400 hours on December 31, 2018, or (2) the later of the termination date of the Western Sales Agreement or the Redding Sales Agreement. All liabilities incurred under this Agreement are hereby preserved until satisfied. Upon termination of this Agreement, Bonneville will offer to extend such services in an agreement to be executed by the Parties for a period of up to 25 years, based upon Bonneville's then standard terms included in similar agreements, provided that no mitigation charges shall be applied, beyond the applicable FERC-approved Bonneville rates, if PacifiCorp requires such service.

2. DEFINITION AND EXPLANATION OF TERMS

(a) "AC Intertie" means Bonneville's rights in the following: two 500 kV transmission lines extending from John Day Substation to the Malin Substation and to the California-Oregon border; portions of John Day, Grizzly, and Malin Substations and the Sand Springs, Fort Rock, and Sycan Compensation Stations; a portion of the Buckley-Summer Lake 500 kV transmission line and associated substations; portions of the Buckley-Marion and Marion-Alvey 500 kV transmission lines and associated facilities; a portion of Bonneville's capacity rights in the Summer Lake-Malin 500 kV transmission line, Bonneville's rights in the Meridian-Malin 500 kV transmission line, Bonneville's share of ownership of the Alvey-Meridian 500 kV transmission line; Captain Jack Substation; the 10 kilometer 500 kV transmission line from Captain Jack Substation to the California-Oregon border; and any modifications, improvements, or additions to such facilities.

(b) "Agreement" means this AC Intertie Transmission Agreement, Contract No. DE-MS79-94BP94285.

(c) "Billing Energy" means the net amount of Electric Energy scheduled in a North-to-South direction and in a South-to-North direction during a month hereunder.

(d) "COB" means the California-Oregon border.

(e) "DC Intertie" means Bonneville's rights in the 1000 kV direct current (DC) transmission line, and associated substation facilities, extending from the Government's Big Eddy Substation to the Nevada-Oregon border.

(f) "Demand Charge" means the demand charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(g) "Effective Control Action" means an action which when taken results in a specific mitigating response at a location or locations in the power system

related to the disturbances of concern, thereby providing acceptable power system performance.

(h) "Effective Date" means 2400 hours on the date of execution.

(i) "Electric Energy" means electric energy, expressed in kilowatthours.

(j) "Electric Power" or "power" means electric peaking capacity, expressed in kilowatts, Electric Energy, or both.

(k) "Energy Charge" means the energy charge specified in Section II.B. of Bonneville's IS-93 Rate, or its successor rate.

(l) "FCRTS" means the Federal Columbia River Transmission System and other Pacific Northwest facilities over which Bonneville has transmission rights.

(m) "FERC" means the Federal Energy Regulatory Commission, or its successor agency.

(n) "LTIAP" means Bonneville's Long-Term Intertie Access Policy, dated May 17, 1988, and amended on April 8, 1993, attached hereto as Exhibit E.

(o) "Operational Constraints" means limitations on the ability of the transmission system to operate due to any system emergency, loading condition, or maintenance outage on Bonneville facilities, or on facilities of an interconnected utility, that make it prudent to reduce AC Intertie loadings, whether or not all facilities are in service.

(p) "OTC" or "Operational Transfer Capability" means the RTC less reductions caused by, but not limited to, physical limitations beyond the control of the Parties, and Operational Constraints, as determined by Bonneville, resulting from, among other things, line or equipment outages, stability limits, or loopflows.

(q) "Pacific Northwest" is as defined in the LTIAP.

(r) "Points of Delivery" means the points, specified and described in Exhibit C, where Electric Power made available by or on behalf of PacifiCorp shall be delivered by Bonneville.

(s) "Points of Interconnection" means the points, specified and described in Exhibit C, where Electric Power shall be made available by or on behalf of PacifiCorp to Bonneville for transmission over the AC Intertie.

(t) "Prudent Utility Practice" means, at any particular time, the generally accepted practices, methods, and acts existing prior thereto in the electrical utility industry, in the Western Systems Coordinating Council area, or, if there are no such practices, methods, and acts, the practices, methods, and acts, which, in the exercise of reasonable judgment in the light of the facts which were known at the time the decision was made, could have been expected to accomplish the desired result consistent with reliability and safety.

(u) "RTC" or "Rated Transfer Capability" means the capability of a transmission line or system to transfer a specified quantity of Electric Power in a prudent and reliable manner.

(v) "Remedial Action Schemes" means sets of fast automatic control actions employed to ensure acceptable power system performance following electrical disturbances as determined by Bonneville power flows and/or stability studies.

(w) "Transmission Demand" means the maximum amount of Electric Power that Bonneville shall be obligated to transmit during an hour hereunder. Such amount is specified in Exhibit C and shall be changed only upon mutual agreement of the parties.

(x) "Workday" means each day that PacifiCorp and Bonneville jointly observe as a regular workday.

3. EXHIBITS AND INTERPRETATIONS

The rights and obligations of the Parties with respect to the provisions hereunder shall be subject to and governed by this Agreement, including Exhibits A through E attached hereto and by this reference made a part of this Agreement. This Agreement sets forth the entire agreement of the Parties as of the date of execution. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement. PacifiCorp shall be the "Transferee" and Bonneville shall be the "Transferor" referred to in Exhibit A. In the event of a conflict between this Agreement and the terms contained in any Exhibit, the terms of this Agreement shall control.

4. TRANSMISSION OF ELECTRIC POWER

(a) Subject to the other provisions of this Agreement, Electric Power shall be transmitted by Bonneville on a firm basis from South-to-North and from North-to-South over the AC Intertie, and PacifiCorp shall schedule pursuant to section 7(a) and make available, or arrange to have made available, to Bonneville at the Points of Interconnection the amounts of Electric Power that PacifiCorp determines are available for transmission to the Points of Delivery hereunder for each hour.

(b) The hourly amounts of Electric Power to be transmitted hereunder shall not exceed the Transmission Demand as specified in Exhibit C.

(c) During times when the North-to-South OTC of the AC Intertie is less than the North-to-South RTC, PacifiCorp's reduced net North-to-South scheduling rights shall be an amount determined by multiplying the North-to-South OTC of the AC Intertie by the ratio of PacifiCorp's North-to-South Transmission Demand to the North-to-South RTC of the AC Intertie. During times when the South-to-North OTC of the AC Intertie is less than the South-to-North RTC, PacifiCorp's reduced net South-to-North scheduling rights shall be an amount determined by multiplying the South-to-North

OTC of the AC Intertie by the ratio of PacifiCorp's South-to-North Transmission Demand to the South-to-North RTC of the AC Intertie.

(d) Bonneville shall have the right to curtail transmission services hereunder to the extent of Operational Constraints. The amount of curtailment shall be consistent with Prudent Utility Practice.

(e) PacifiCorp shall be responsible for providing or assuring at its cost the provision of its pro rata share of Remedial Action Schemes required to support the RTC and OTC of the AC Intertie in either the South-to-North or North-to-South direction. Bonneville and PacifiCorp shall jointly plan and coordinate the implementation of the Remedial Action Schemes. No Party shall unduly withhold consent regarding the implementation of the Remedial Action Schemes. PacifiCorp may implement the required Remedial Action Schemes where it chooses on its system as long as the required level of Effective Control Action is obtained. The level of reliability of the Remedial Action Scheme design on PacifiCorp's system shall be at least equal to the level of reliability employed in the design of the overall AC Intertie Remedial Action Scheme.

(1) PacifiCorp's contribution to the total operational responsibility for this Remedial Action Scheme shall be that part of the total responsibility determined by the ratio of the Transmission Demand to the total RTC of the AC Intertie.

(2) Bonneville shall provide the appropriate control signal or signals to PacifiCorp.

(3) PacifiCorp shall provide the necessary equipment to receive and transmit the control signal or signals to and from PacifiCorp's transmission, generation, and/or control center facilities to arm and initiate the appropriate Effective Control Action or Actions as determined by Bonneville.

(4) In support of its obligations to provide generator dropping for its net North-to-South AC Intertie schedules, PacifiCorp shall provide generator dropping from its share of Mid-Columbia generation on-line at the time of the Remedial Action Scheme requirement.

(5) Bonneville may, after it has exhausted its own capability to provide generator dropping in support of its obligation for net North-to-South AC Intertie schedules, have access to PacifiCorp's total Mid-Columbia rights on-line at the time of the Remedial Action Scheme requirement. Such access to PacifiCorp's Mid-Columbia generator dropping capability by Bonneville shall be at no cost to Bonneville.

(6) To the extent that PacifiCorp does not have the capability on-line to provide generator dropping from its Mid-Columbia rights for its net North-to-South AC Intertie schedules, Bonneville shall, to the extent it has available on-line generation, provide generator dropping capability to PacifiCorp at no cost to PacifiCorp.

(7) In support of PacifiCorp's net South-to-North schedules on the AC Intertie, PacifiCorp shall be responsible for making arrangements for any load dropping requirements.

(8) To the extent possible, as determined by Bonneville, Bonneville shall offer to sell Remedial Action Scheme service to PacifiCorp to enable PacifiCorp to meet its obligations under this section 4(e).

(9) Nothing in this section 4(e) shall be construed so as to diminish in any way PacifiCorp's obligation to provide or assure, at its cost, the provision of its pro-rata share of remedial action schemes required to support the RTC and the OTC of the AC Intertie in either the North-to-South or South-to-North direction.

(f) When PacifiCorp schedules deliveries pursuant to this Agreement or any agreement for use of AC Intertie capacity entered into pursuant to the LOU, including future Pacific Northwest AC Intertie Capacity Ownership

Agreements, PacifiCorp shall not be required to obtain additional main grid wheeling on Bonneville's system unless insufficient capacity exists in the combined capability of the Midpoint-Malin 500 kV line, the Malin-Meridian Line, and the Alvey-Meridian line for PacifiCorp to use its scheduling rights available to it. If there is insufficient capacity in the combined capability of the Midpoint-Malin line, the Malin-Meridian Line, or the Alvey-Meridian Line, charges will be applied by Bonneville to PacifiCorp consistent with subsection 5(e)(3) of the AC Intertie Agreement, Contract No. DE-MS79-94BP94332.

5. PAYMENT PROVISIONS

(a) As compensation for the AC Intertie transmission services provided hereunder, PacifiCorp shall pay Bonneville, in accordance with the provisions of Exhibits B and C, and as follows:

(1) PacifiCorp shall pay Transmission Demand charges for North-to-South and for South-to-North service, which shall equal the sum of the products obtained by multiplying the North-to-South and the South-to-North Transmission Demands for each month by the Demand Charge; and

(2) PacifiCorp shall pay for energy transmitted hereunder each month, determined as follows:

(A) For North-to-South service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall be the greater of (1) the product obtained by multiplying the North-to-South Billing Energy for each month by the Energy Charge, or (2) a minimum energy payment, based upon the Energy Charge and an 85 percent load factor. Such minimum energy payment shall be calculated as follows: Transmission Demand (MW) x 8760 hours x Energy Charge (m/kWh) x 0.85 ÷ 12; and

(B) For South-to-North service, PacifiCorp shall pay an amount for energy transmitted hereunder which shall equal the product obtained by multiplying the South-to-North Billing Energy for each month by the Energy Charge.

(C) Such payment shall include charges determined by multiplying the amount of hourly losses, calculated in accordance with the transmission loss factor specified in Exhibit D, by the Energy Charge.

6. TRANSMISSION LOSSES

To compensate Bonneville for Electric Power losses incurred in providing the services hereunder, both for deliveries from PacifiCorp and for deliveries to PacifiCorp, PacifiCorp shall schedule and make available to Bonneville on the corresponding hour 168 hours later or on another hour to be agreed upon by the Parties, and at points to be agreed upon by the Parties, the amounts of Electric Power calculated in accordance with the Loss Factors specified in Exhibit D.

7. POWER SCHEDULING

PacifiCorp shall submit, or arrange to have submitted, to Bonneville by 1400 hours Pacific Time on each Workday:

(a) a separate schedule for North-to-South and South-to-North transfers of Electric Power to be made available to Bonneville for each hour of the following day or days through the next Workday. Such North-to-South and South-to-North schedules may be netted against each other. Changes to such schedules by PacifiCorp shall be accepted up to 30 minutes prior to the hour for which such schedule change is desired;

(b) separate schedules of the hourly amounts of Electric Power to be made available pursuant to section 6 for transmission losses for each hour of the following day or days through the next Workday;

(c) changes to schedules other than those permitted pursuant to subsection 7(a) shall be accepted at any time as mutually agreed by the Parties.

8. REVISION OF EXHIBITS

(a) The initial rate schedules attached as Exhibit B have been confirmed and approved by the FERC on an interim basis. The UFT rate schedule has been approved on a final basis. If the final rate schedules which are approved by the FERC are amendments or modifications of the initial rate schedules, the applicable amended or modified rate schedules and associated General Transmission Rate Schedule Provisions shall be attached hereto and made a part of this Agreement effective as of the date specified in the FERC's approval.

(b) The rate schedules and General Transmission Rate Schedule Provisions included in Exhibit B shall be replaced by successor rate schedules and provisions in accordance with the provisions of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) and FERC rules.

(c) Bonneville shall annually review Exhibit D and shall revise such exhibit as appropriate to incorporate values which represent then current AC Intertie and DC Intertie operating conditions or to incorporate any value, used in such exhibit to calculate the Electric Power losses, which has changed due to a change in methodology. Any changes to the loss methodology or formula, other than numerical values, shall only be made after consultation with PacifiCorp. Bonneville shall prepare a new Exhibit D incorporating any revision and the revised exhibit shall become effective as of the date specified therein.

(d) If Bonneville determines that any charge specified in this Agreement must be changed pursuant to sections 19 or 38 of Exhibit A, it shall prepare a revised exhibit as appropriate incorporating such revised charges. Such new exhibit

shall be substituted for the exhibit then in effect and shall become effective as of the date specified therein.

(e) If the Parties agree to any changes to Exhibit C pursuant to this Agreement Bonneville shall prepare and issue a revised Exhibit C.

9. WAIVER OF BONNEVILLE'S ENERGY SERVICE OBLIGATION

(a) PacifiCorp agrees that the disposition of Electric Energy for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement shall result in a reduction of Bonneville's obligation to PacifiCorp under section 5(b) of the Northwest Power Act. Bonneville's obligation to supply firm power under the Power Sales Contract, as amended or replaced, shall be reduced by the maximum amount of Electric Energy which PacifiCorp is obligated to provide for use outside the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement. Bonneville shall implement such reduction as described in subsection (b) below.

(b) To carry out the provisions of subsection (a) above, PacifiCorp shall submit to Bonneville a revised Firm Resources Exhibit and associated data as specified under the Power Sales Contract effective on the effective date of the notice pursuant to subsection (a) above. The Firm Resources Exhibit shall include, as a Firm Resource, the amount of PacifiCorp's obligation to provide Electric Energy for use outside of the Pacific Northwest pursuant to the Western Sales Agreement and the Redding Sales Agreement.

10. COMPLIANCE WITH LONG-TERM INTERTIE ACCESS POLICY

Except as otherwise specified in this Agreement, transmission service provided by Bonneville to PacifiCorp over the AC Intertie shall be subject to the terms of the LTIAP. Notwithstanding the terms of the LTIAP, the Parties agree that no mitigation charges shall be applicable under this Agreement. The Parties also agree that the transmission services being provided hereunder are in accordance with Section 4(b) of the LTIAP (New Transactions not subject to Capacity Limits). The

terms of this Agreement shall not be subject to change upon amendment of the LTIAP, except by mutual agreement of the parties; provided, however, Bonneville may change the Protected Areas Exhibit C to the LTIAP and apply such changes prospectively to resources not licensed at the time of the change without the agreement of PacifiCorp. A resource which has been licensed in the past, and for which a new license is pending, shall be considered licensed.

11. PACIFIC NORTHWEST AC INTERTIE CAPACITY OWNERSHIP EXCHANGE RIGHTS

PacifiCorp shall have the right to exchange all or a portion of its AC Intertie firm transmission contract rights acquired under this Agreement with any party receiving Pacific Northwest AC Intertie Capacity Ownership (Capacity Ownership) rights for up to 125 MW of Capacity Ownership rights, to the extent the Capacity Ownership party has rights to assign all or a portion of its Capacity Ownership allocation. To the extent Bonneville has a first right of refusal to acquire Capacity Ownership rights from a Capacity Ownership party, PacifiCorp's exchange rights under this section 11 shall have priority. Such exchange between PacifiCorp and the Capacity Ownership party shall be approved by Bonneville, which approval shall not unreasonably be withheld, and shall ensure that rights, benefits and obligations

to Bonneville under the affected agreements are preserved.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement in several counterparts.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
ACTING *Assistant Administrator for Power Sales*

Name Sydney D. Berwager
(Print/Type)

Date 5/26/94

PACIFICORP

By _____

Name Dennis P. Steinberg
(Print/Type)

Title Senior Vice President

Date June 1, 1994

(PMTT-8170-W:PMT\CT\PACAD.DOC)

GWP Form-4R (04-15-83)

GENERAL WHEELING PROVISIONS

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GENERAL APPLICATION

1. Interpretation.

(a) The provisions in this exhibit shall be deemed to be a part of the contract body to which they are an exhibit. If a provision in such contract body is in conflict with a provision contained herein, the former shall prevail.

(b) If a provision in the General Transmission Rate Schedule Provisions is in conflict with a provision in this exhibit or the contract body, this exhibit or the contract body shall prevail.

(c) Nothing contained in this contract shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. As used in this contract:

(a) "Contractor," "Utility" or "Borrower" means the party to this contract other than Bonneville.

(b) "Federal System" or "Federal System Facilities" means the facilities of the Federal Columbia River Power System, which for the purposes of this contract shall be deemed to include the generating facilities of the Government in the Pacific Northwest for which Bonneville is designated as marketing agent; the facilities of the Government under the jurisdiction of Bonneville; and any other facilities:

(1) from which Bonneville receives all or a portion of the generating capability (other than station service) for use in meeting Bonneville's loads, such facilities being included only to the extent Bonneville has the right to receive such capability; provided, however, that "Bonneville's loads" shall not include that portion of the loads of any Bonneville customer which are served by a nonfederal generating resource purchased or owned directly by such customer which may be scheduled by Bonneville;

(2) which Bonneville may use under contract, or license; or

(3) to the extent of the rights acquired by Bonneville pursuant to the Treaty, between the Government and Canada, relating to the cooperative development of water resources of the Columbia River Basin, signed in Washington, D.C., on January 17, 1961.

(c) "Integrated Demand" means the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour.

(d) "Measured Demand" means the maximum Integrated Demand for a billing month determined from measurements made as specified in the contract or as determined in section 4 hereof when metering or other data are not available

for such purpose. Bonneville, in determining the Measured Demand, will exclude any abnormal Integrated Demands due to, or resulting from (a) emergencies or breakdowns on, or maintenance of, either parties' facilities, and (b) emergencies on facilities of the Transferee, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville.

If the contract provides for delivery of more than one class of power to a Transferee at any Point of Delivery, the portion of each Integrated Demand assigned to any class of power shall be determined as specified in the contract. The portion of the Integrated Demand so assigned shall constitute the Measured Demand for such class of power.

(e) "Month" means the period commencing at the time when the meters mentioned in this contract are read by Bonneville and ending approximately 30 days thereafter when a subsequent reading of such meters is made by Bonneville.

(f) "Point(s) of Delivery" means the point(s) of delivery listed either in the Points of Delivery Exhibit to this contract or in the body of this contract.

(g) "System" or "Facilities" means the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

(h) "Transferee" means an entity which receives power or energy from the system of the Transferor.

(i) "Transferor" means an entity which receives at one point on its system a supplying entity's power or energy and makes such power or energy available at another point on its system for the account of the delivering entity or a third party.

(j) "Uncontrollable Forces" means:

(1) strikes or work stoppage affecting the operation of the Contractor's works, system, or other physical facilities or of the Federal System Facilities or the physical facilities of any Transferee upon which such operation is completely dependent; the term "strikes or work stoppage" shall be deemed to include threats of imminent strikes or work stoppage which reasonably require a party or Transferee to restrict or terminate its operations to prevent substantial loss or damage to its works, system, or other physical facilities; or

(2) such of the following events as the Contractor or Bonneville or any Transferee by exercise of reasonable diligence and foresight, could not reasonably have been expected to avoid:

(A) events, reasonably beyond the control of either party or any Transferee, causing failure, damage, or destruction of any works, system or facilities of such party or Transferee; the word "failure"

shall be deemed to include interruption of, or interference with, the actual operation of such works, system, or facilities;

(B) floods or other conditions caused by nature which limit or prevent the operation of, or which constitute an imminent threat of damage to, any such works, system, or facilities; and

(C) orders and temporary or permanent injunctions which prevent operation, in whole or in part, of the works, system, or facilities of either party or any Transferee, and which are issued in any bona fide proceeding by:

i. any duly constituted court of general jurisdiction; or

ii. any administrative agency or officer, other than Bonneville or its officers, provided by law (a) if said party or Transferee has no right to a review of the validity of such order by a court of competent jurisdiction; or (b) if such order is operative and effective unless suspended, set aside, or annulled by a court of competent jusidiction and such order is not suspended, set aside, or annulled in a judicial proceeding prosecuted by said party or Transferee in good faith; provided, however, that if such order is suspended, set aside, or annulled in such a judicial proceeding, it shall be deemed to be an "uncontrollable force" for the period during which it is in effect; provided, further, that said party or Transferee, shall not be required to prosecute such a proceeding, in order to have the benefits of this section, if the parties agree that there is no valid basis for contesting the order.

The term "operation" as used in this subsection shall be deemed to include construction, if construction is required to implement the contract and is specified therein.

3. Prior Demands.

(a) In determining any credit demand mentioned in, or money compensation to be paid under this contract for any month, Integrated Demands at which electric energy was delivered by the Transferor at Points of Delivery mentioned herein for the account of the other party to this contract prior to the date upon which the contract takes effect shall be considered in the same manner as if this contract had been in effect.

(b) If either party has delivered electric power and energy to the other party at any Point of Delivery specified in this contract or in any previous contract, and such Point of Delivery is superseded by another Point of Delivery specified in this contract, the Measured Demands, if any, at the superseded Point of Delivery shall be considered for the purpose of determining the charges paid to the Transferor for the electric power and energy delivered under this contract at such superseded point.

4. Measurements. Except as it is otherwise provided in section 7, each measurement of each meter mentioned in this contract shall be the measurement

automatically recorded by such meter or, at the request of either party, the measurement as mutually determined by the best available information.

If it is provided in this contract that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by the parties hereto. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such change in conditions.

5. Measurements and Installation of Meters. Bonneville may at any time install a meter or metering equipment to make the measurements for any Point of Delivery required for any computation or determination mentioned in this contract, and if so installed, such measurements shall be used thereafter in such computation or determination.

6. Tests of Metering Installations. Each party to this contract shall, at its expense, test its metering installations associated with this contract at least once every two years, and, if requested to do so by the other party, shall make additional tests or inspections of such installations, the expense of which shall be paid by such other party unless such additional tests or inspections show the measurements of such installations to be inaccurate as specified in section 7. Each party shall give reasonable notice of the time when any such test or inspection is to be made to the other party who may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate shall be adjusted, repaired or replaced to provide accurate metering.

7. Adjustment for Inaccurate Metering

(a) If any meter mentioned in this contract fails to register, or if the measurement made by such meter during a test made as provided in section 6 varies by more than one percent from the measurement made by the standard meter used in such test, or if an error in meter reading occurs, adjustment shall be made correcting all measurements for the actual period during which such innacurate measurements were made, if such period can be determined. If such period cannot be determined, the adjustment shall be made for the period immediately preceding the test of such meter which is equal to the lesser of (a) one-half the time from the date of the last preceding test of such meter, or (b) six months. Such corrected measurements shall be used to recompute the amounts of any electric power and energy to be made available, or any credits to be made in any exchange energy account, and of any money compensation to be paid to the Transferor as provided in this contract.

(b) If the credit theretofore made to the Transferor in the exchange energy account varies from the credit to be made as recomputed, the amount of the variance will be credited in such exchange energy account to the party entitled thereto.

(c) If the money compensation theretofore paid to the Transferor varies from the money compensation to be paid as recomputed, the amount of the variance will be paid to the party entitled thereto after both parties have agreed to such recomputation and within 30 days after receipt of invoice by the designated payment office of the payer; provided, however, that the other

party may deduct such amount due it from any money compensation which thereafter becomes due the Transferor under this contract.

8. Character of Service. Unless otherwise specifically provided for in the contract, electric power and energy made available pursuant to this contract shall be in the form of three-phase current, alternating at a nominal frequency of 60 hertz.

9. Point(s) of Delivery and Delivery Voltage. Electric power and energy shall be delivered to each Transferee at such point or points and at such voltage or voltages as are agreed upon by the parties hereto.

10. Combining Deliveries Coincidentally. If it is provided in this contract that charges for electric power and energy made available at two or more Points of Delivery will be made by combining deliveries at such points coincidentally:

(a) the total Measured Demand to be considered in determining the billing demand for each billing month shall be the largest sum obtained by adding for each demand interval of such month the corresponding Integrated Demands of the Transferee at all such points after adjusting said Integrated Demands as appropriate to such points;

(b) the number of kilowathours to be used in determining the energy charge, if any, and the average power factor at which electric energy is delivered at such points under this contract, during such month, shall be the sum of the amounts of electric energy delivered at such points under this contract during such month; and

(c) the number of reactive kilovolt-ampere-hours to be used in determining such average monthly power factor shall be the sum of the reactive kilovolt-ampere-hours delivered at such points under this contract such month.

11. Suspension of Deliveries. The other party to this contract may at any time notify the Transferor in writing to suspend the deliveries of electric power and energy provided for in this contract. Upon receipt of any such notice, the Transferor will forthwith discontinue, and will not resume, such deliveries until notified to do so by the other party, and upon receipt of such notice from the other party to do so, will forthwith resume such deliveries.

12. Continuity of Service. Either party may temporarily interrupt or reduce deliveries of electric power and energy if such party determines that such interruption or reduction is necessary or desirable in case of system emergencies, Uncontrollable Forces, or in order to install equipment in, make repairs to, make replacements within, make investigations and inspections of, or perform other maintenance work on its system. Except in case of emergency and in order that each party's operations will not be unreasonably interfered with, such party shall give notice to the other party of any such interruption or reduction, the reason therefor, and the probable duration thereof to the extent such party has knowledge thereof. Each party shall effect the use of temporary facilities or equipment to minimize the effect of any such interruption or outage to the extent reasonable or appropriate.

13. Uncontrollable Forces. Each party shall notify the other as soon as possible of any Uncontrollable Forces which may in any way affect the delivery of power hereunder. In the event the operations of either party are interrupted or curtailed due to such Uncontrollable Forces, such party shall exercise due diligence to reinstate such operations with reasonable dispatch.

14. *Reducing Charges for Interruptions.* If deliveries of electric power and energy to the Transferee are suspended, interrupted, interfered with or curtailed due to Uncontrollable Forces on either the Transferee's System or Transferor's System, or if the Transferor interrupts or reduces deliveries to the Transferee for any of the reasons stated in section 12 hereof, the credit in the exchange energy account which would otherwise be made, or the money compensation which would otherwise be paid to the Transferor, shall be appropriately reduced. No interruption, or equivalent interruption, of less than 30 minutes duration will be considered for computation of such reduction in charges.

15. Net Billing. Upon mutual agreement of the parties, payment due one party may be offset against payments due the other party under all contracts between the parties hereto for the sale and exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, lease of electric facilities, mutual supply of emergency and standby electric power and energy, and under such other contracts between such parties as the parties may agree, unless otherwise provided in existing contracts between the parties. Under contracts included in this procedure, all payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists unless the latter elects to have such balance carried forward to be added to the payments due it in a succeeding month.

16. Average Power Factor.

(a) The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{/(\text{Kilowatthours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

(b) When delivery of electric power and energy by the Transferor at any point is commingled with any other class or classes of power and it is impracticable to separately meter the kilowatthours and reactive kilovolt-ampere-hours for each class, the average power factor of the total delivery of such electric power and energy for the month will be used, where applicable, as the power factor for each of the separate classes.

(c) Except as it is otherwise specifically provided in this contract, no adjustment will be made for power factor at any point of delivery described in this contract while the varhours delivered at such point are not measured.

(d) The Transferor may, but shall not be obligated to, deliver electric energy hereunder at a power factor of less than 0.85 leading or lagging.

17. Permits.

(a) If any equipment or facilities associated with any Point of Delivery and belonging to a party to this contract are or are to be located on the property of the other party, a permit to install, test, maintain, inspect, replace, repair, and operate during the term of this contract and to remove such equipment and facilities at the expiration of said term, together with the right of entry to said property at all reasonable times in such term, is hereby granted by the other party.

(b) Each party shall have the right at all reasonable times to enter the property of the other party for the purpose of reading any and all meters mentioned in this contract which are installed on such property.

(c) If either party is required or permitted to install, test, maintain, inspect, replace, repair, remove, or operate equipment on the property of the other, the owner of such property shall furnish the other party with accurate drawings and wiring diagrams of associated equipment and facilities, or, if such drawings or diagrams are not available, shall furnish accurate information regarding such equipment or facilities. The owner of such property shall notify the other party of any subsequent modification which may affect the duties of the other party in regard to such equipment, and furnish the other party with accurate revised drawings, if possible.

18. Ownership of Facilities.

(a) Except as otherwise expressly provided, ownership of any and all equipment, and of all salvable facilities installed or previously installed by a party to this contract on the property of the other party shall be and remain in the installing party.

(b) Each party shall identify all movable equipment and all other salvable facilities which are installed by such party on the property of the other by permanently affixing thereto suitable markers plainly stating the name of the owner of the equipment and facilities so identified. Within a reasonable time subsequent to initial installation, and subsequent to any modification of such installation, representatives of the parties shall jointly prepare an itemized list of said movable equipment and facilities.

19. Adjustment for Change of Conditions. If changes in conditions hereafter occur which substantially affect any factor required by this contract to be used in determining (a) any credit in any exchange energy account to be made, money compensation to be paid, or amount of electric power and energy or losses to be made available to one party by the other party, or (b) any maximum replacement demand, or average power factor mentioned in this contract, such factor will be changed in an equitable manner which will conform to such changes of conditions. If an increase in the capacity of the facilities being used by the Transferor in making deliveries hereunder is required at any time after execution of this contract to enable the Transferor to make the deliveries herein required together with those required for its own operations, the construction or installation of additional or other

equipment or facilities for that purpose shall be deemed to be a change of conditions within the meaning of the preceding sentence.

If, pursuant to the terms of the agreement establishing such exchange energy account, another rate is substituted for the rate to be used in settling the balance in such account, the number of kilowatthours to be credited to the Transferor in such account for each month as provided in this agreement, shall be changed for each month thereafter to the amount computed by multiplying such number of kilowatthours by 2.5 mills and dividing the resulting product by the currently effective substituted rate in mills per kilowatthour.

20. Dispute Resolution and Arbitration.

(a) Pending resolution of a disputed matter the parties will continue performance of their respective obligations pursuant to this contract. If the parties cannot reach timely mutual agreement on any matter in the administration of this contract Bonneville shall, unless otherwise specifically provided for in subsection (b) below and, to the extent necessary for its continued performance, make a determination of such matter without prejudice to the rights of the other party. Such determination shall not constitute a waiver of any other remedy belonging to the Contractor.

(b) The questions of fact stated below shall be subject to arbitration. Other questions of fact under this contract may be submitted to arbitration upon written mutual agreement of the parties. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated and the arbitrator appointed by such party. The other party shall, within 10 days after the receipt of such notice, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said 10 days, or in case the two so appointed fail for 10 days to agree upon and appoint a third, the party calling for the arbitration, upon 5 days' written notice delivered to the other party, shall apply to the person who at the time shall be the presiding judge of the United States Court of Appeals for the Ninth Circuit for appointment of the second and third arbitrator, as the case may be.

The determination of the question or questions submitted for arbitration shall be made by a majority of the arbitrators and shall be binding on the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, for its own attorney fees, and for compensation for its witnesses or consultants. All other costs incurred in connection with the arbitration shall be shared equally by the parties thereto.

The questions of fact to be determined as provided in this section shall be limited to:

(1) the determination of the measurements to be made by the parties hereto pursuant to section 4;

(2) the correction of the measurements to be made pursuant to section 7;

(3) the duration of the interruption or equivalent interruption in section 14;

(4) whether changes in conditions mentioned in section 19 have occurred;

(5) whether the changes mentioned in section 30 were made "promptly";

(6) whether an increase or decrease in load or change in load factor mentioned in section 32 is unusual;

(7) any issue which both parties agree is an issue of fact mentioned in sections 30, 31, and 34;

(8) the occurrence of an abnormal nonrecurring demand and the amount and time thereof;

(9) whether a party has complied with section 34(b); and

(10) the acceptable level of harmonics for purposes of section 35.

21. Contract Work Hours and Safety Standards.

This contract, if and to the extent required by applicable law and if not otherwise exempted, is subject to the following provisions:

(a) Overtime Requirements. No Contractor or subcontractor contracting for any part of the contract work which may require or involve the employment of laborers or mechanics, shall require or permit any laborer or mechanic in any workweek in which such worker is employed on such work to work in excess of 8 hours in any calendar day or in excess of 40 hours in such workweek unless such laborer or mechanic receives compensation at a rate not less than one and one-half times such worker's basic rate of pay for all hours worked in excess of eight hours in any calendar day or in excess of 40 hours in such workweek, as the case may be.

(b) Violation; Liability for Unpaid Wages; Liquidated Damages. In the event of any violation of the provisions of subsection (a), the Contractor and any subcontractor responsible therefor shall be liable to any affected employee for such employee's unpaid wages. In addition, such contractor and subcontractor shall be liable to the Government for liquidated damages. Such liquidated damages shall be computed with respect to each individual laborer or mechanic employed in violation of the provisions of subsection (a) in the sum of $10 for each calendar day on which such employee was required or permitted to be employed in such work in excess of eight hours or in excess of such employee's standard workweek of 40 hours without payment of the overtime wages required by subsection (a) above.

(c) Withholding for Unpaid Wages and Liquidated Damages. Bonneville may withhold or cause to be withheld, from any moneys payable on account of work performed by the Contractor or subcontractor, such sums as may administratively be determined to be necessary to satisfy any liabilities of such Contractor or subcontractor for unpaid wages and liquidated damages as provided in subsection (b) above.

(d) Subcontracts. The Contractor shall insert in any subcontracts the clauses set forth in subsections (a) through (c) of this provision and also a clause requiring the subcontractors to include these clauses in any lower tier subcontracts which they may enter into, together with a clause requiring this insertion in any further subcontracts that may in turn be made.

(e) Records. The Contractor shall maintain payroll records containing the information specified in 29 CFR 516.2(a). Such records shall be preserved for 3 years from the completion of the contract.

22. Convict Labor. In connection with the performance of work under this contract, the Contractor agrees, if and to the extent required by applicable law or if not otherwise exempted, not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4082(c)(2)) and Executive Order 11755, December 29, 1973.

23. Equal Employment Opportunity. During the performance of this contract, if and to the extent required by applicable law or if not otherwise exempted, the Contractor agrees as follows:

(a) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to, the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by Bonneville setting forth the provisions of the Equal Opportunity clause.

(b) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(c) The Contractor will send to each labor union or representative of workers with which said Contractor has a collective bargaining agreement or other contract or understanding, a notice, to be provided by Bonneville, advising the labor union or worker's representative of the Contractor's commitments under this Equal Opportunity clause and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) The Contractor will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) The Contractor will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations, and relevant orders of the Secretary of Labor, or pursuant

thereto, and will permit access to said Contractor's books, records, and accounts by Bonneville and the Secretary of Labor for purposes of investigations to ascertain compliance with such rules, regulations, and orders.

(f) In the event of the Contractor's noncompliance with the Equal Opportunity clause of this contract or with any of such rules, regulations, or orders, this contract may be cancelled, terminated, or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order No. 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(g) The Contractor will include the provisions of paragraphs (a) through (f) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as Bonneville may direct as a means of enforcing such provisions, including sanctions for noncompliance. In the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction by Bonneville, the Contractor may request the Government to enter into such litigation to protect the interests of the Government.

24. Additional Provisions. The Contractor agrees to comply with the clauses for Government contracts contained in the following statutes, Executive Orders, and regulations to the extent applicable:

(a) the Rehabilitation Act of 1973, Public Law 93-112, as amended, and 41 CFR 60-741 (affirmative action for handicapped workers);

(b) the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 92-540, as amended, and 41 CFR 60-250 (affirmative action for disabled veterans and veterans of the Vietnam era);

(c) Executive Order 11625 and 41 CFR 1-1.1310-2 (utilization of minority business enterprises);

(d) the Small Business Act, as amended.

25. Reports. The other party to this contract will furnish Bonneville such information as is necessary for making any computation required for the purposes of this contract, and the parties will cooperate in exchanging such additional information as may be reasonably useful for their respective operations.

26. Assignment of Contract. This contract shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this contract. Such contract or any interest therein shall not be transferred or assigned by either party to any party other than the Government or an agency thereof without the written consent of the other except as

specifically provided in this section. The consent of Bonneville is hereby given to any security assignment or other like financing instrument which may be required under terms of any mortgage, trust, security agreement or holder of such instrument of indebtedness made by and between the Contractor and any mortgagee, trustee, secured party, subsidiary of the Contractor or holder of such instrument of indebtedness, as security for bonds of other indebtedness of such Contractor, present or future; such mortagagee, trustee, secured party, subsidiary, or holder may realize upon such security in foreclosure or other suitable proceedings, and succeed to all right, title, and interests of such Contractor.

27. Waiver of Default. Any waiver at any time by any party to this contract of its rights with respect to any default of any other party thereto, or with respect to any other matter arising in connection with such contract, shall not be considered a waiver with respect to any subsequent default or matter.

28. Notices and Computation of Time. Any notice required by this contract to be given to any party shall be effective when it is received by such party, and in computing any period of time from such notice, such period shall commence at 2400 hours on the date of receipt of such notice.

29. Interest of Member of Congress. No Member of, or Delegate to Congress, or Resident Commissioner shall be admitted to any share or part of this contract or to any benefit that may arise therefrom, but this provision shall not be construed to extend to this contract if made with a corporation for its general benefit.

APPLICABLE ONLY IF TRANSFEREE IS A PARTY TO THIS CONTRACT

30. Balancing Phase Demands. If required by the Transferor at any time during the term of this contract, the Transferee shall promptly make such changes as are necessary on its system to balance the phase currents at any Point of Delivery so that the current of any one phase shall not exceed the current on any other phase at such point by more than 10 percent.

31. Adjustment for Unbalanced Phase Demands. If the Transferee fails to promptly make the changes mentioned in section 30, the Transferor may, after giving written notice one month in advance, determine that the Measured Demand of the Transferee at the Point of Delivery in question during each month thereafter, until such changes are made, is equal to the product obtained by multiplying by three the largest of the Integrated Demands on any phase adjusted as appropriate to such point during such month.

32. Changes in Requirements or Characteristics. The Transferee will, whenever possible, give reasonable notice to the Transferor of any unusual increase or decrease of its demands for electric power and energy on the Transferor's system, or of any unusual change in the load factor or power factor at which the Transferee will take delivery of electric power and energy under this contract.

33. Inspection of Facilities. Each party may for any reasonable purpose under this contract inspect the other party's electric installation at any reasonable time. Such inspection, or failure to inspect, shall not render

such party, its officers, agents, or employees, liable or responsible for any injury, loss, damage, or accident resulting from defects in such electric installation, or for violation of this contract. The inspecting party shall observe written instructions and rules posted in facilities and such other necessary instructions or standards for inspection as the parties agree to. Only those electric installations used in complying with the terms of this contract shall be subject to inspection.

34. Electric Disturbances.

(a) For the purposes of this section, an electric disturbance is any sudden, unexpected, changed, or abnormal electric condition occurring in or on an electric system which causes damage.

(b) Each party shall design, construct, operate, maintain and use its electric system in conformance with accepted utility practices:

(1) to minimize electric disturbances such as, but not limited to, the abnormal flow of power which may damage or interfere with the electric system of the other party or any electric system connected with such other party's electric system; and

(2) to minimize the effect on its electric system and on its customers of electric disturbances originating on its own or another electric system.

(c) If both parties to this contract are parties to the Western Interconnected Electric System Agreement, their relationship with respect to system damages shall be governed by that Agreement.

(d) During such time as a party to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, its relations with the other party with respect to system damages shall be governed by the following sentence, notwithstanding the fact that the other party may be a party to said Agreement Limiting Liability Among Western Interconnected Systems. A party to this contract shall not be liable to the other party for damage to the other party's system or facilities caused by an electric disturbance on the first party's system, whether or not such electric disturbance is the result of negligence by the first party, if the other party has failed to fulfill its obligations under subsection (b)(2) above.

(e) If one of the parties to this contract is not a party to the Agreement Limiting Liability Among Western Interconnected Systems, each party to this contract shall hold harmless and indemnify the other party, its officers and employees, from any claims for loss, injury, or damage suffered by those to whom the first party delivers power not for resale, which loss, injury or damage is caused by an electric disturbance on the other party's system, whether or not such electric disturbance results from the negligence of such other party, if such first party has failed to fulfill its obligations under subsection (b)(2) above, and such failure contributed to the loss, injury or damage.

(f) Nothing in this section shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this contract.

35. Harmonic Control. Each party shall design, construct, operate, maintain and use its electric facilities in accordance with good engineering practices to reduce to acceptable levels the harmonic currents and voltages which pass into the other party's facilities. Harmonic reductions shall be accomplished with equipment which is specifically designed and permanently operated and maintained as an integral part of the facilities of the party which owns the system on which harmonics are generated.

APPLICABLE ONLY IF TRANSFEREE IS NOT A PARTY TO THIS CONTRACT

36. Protection of the Transferor. Protection is or will be afforded to Bonneville or its Transferor under such of the following provisions and conditions as are specified in each contract executed or to be executed by Bonneville and each third party Transferee named in this contract: the power factor clause of the applicable Bonneville Wholesale Rate Schedule and the subject matter set forth in the General Contract Provisions under the following titles, namely:

Adjustment for Unbalanced Phase Demands; Uncontrollable Forces; Continuity of Service; Changes in Demands or Characteristics; Electric Disturbances; Harmonic Control; Balancing Phase Demands; Permits; Ownership of Facilities; and Inspection of Facilities.

RELATING TO RURAL ELECTRIFICATION ADMINISTRATION BORROWERS

37. Approval of Contract. If the Contractor borrows from the Rural Electrification Administration or any other entity under an indenture which requires the lender's approval of contracts, this contract and any amendment thereto shall not be binding on the parties thereto if they are not approved by the Rural Electrification Administration or such other entity. The Contractor shall notify Bonneville of any such entity. If approval is given, such contract or amendment shall be effective at the time stated therein.

APPLICABLE ONLY IF BONNEVILLE IS THE TRANSFEROR

38. Equitable Adjustment of Rates.

(a) Bonneville shall establish, periodically review and revise rates for the wheeling of electric power and/or energy pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

(b) As used in this section, the words "Rate Adjustment Date" shall mean any date specified by Bonneville in a notice of intent to file revised rates as published in the Federal Register; provided, however, that such date shall not occur sooner than (1) nine months from the date that such notice of intent is published; or (2) twelve months from any previous Rate Adjustment Date. By giving written notice to the Contractor 45 days prior to such Rate Adjustment Date, Bonneville may delay such Rate Adjustment Date for up to 90 days if Bonneville determines either that the revenue level of the proposed rates

differs by more than five percent from the revenue requirements indicated by most recent repayment studies entered in the hearings record or that external events beyond Bonneville's control will prevent Bonneville from meeting such Rate Adjustment Date. Bonneville may cancel a notice of intent to file revised rates at any time (1) by written notice to the Contractor; or (2) by publishing in the Federal Register a new notice of intent to file revised rates which specifically cancels a previous notice.

(c) The Contractor shall pay Bonneville for the service made available under this contract during the period commencing on each Rate Adjustment Date and ending at the beginning of the next Rate Adjustment Date at the rate specified in any rate schedule available at the beginning of such period for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof, and of the General Transmission Rate Schedule Provisions, if any, as changed with, incorporated in or referred to in such rate schedule. New rates shall not be effective on any Rate Adjustment Date unless they have been approved on a final or interim basis by a governmental agency designated by law to approve Bonneville's rates. Rates shall be applied in accordance with the terms thereof, the General Transmission Rate Schedule Provisions as changed with, incorporated in or referred to in such rate schedule and the terms of this contract.

(WP-PKJ-0222f)

Exhibit B

1993

TRANSMISSION RATE SCHEDULES AND

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

Transmission Parameters

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1]

1. North-to-South Transactions:

   a. 01/01/94 to 05/31/94: 75 MW

   b. 06/01/94 and thereafter: 125 MW

2. South-to-North Transactions:

   a. 01/01/94 to 05/31/94: 75 MW x Intertie South-to-North RTC ÷ 4800 MW

   b. 06/01/94 and thereafter: 125 MW x Intertie South-to-North RTC ÷ 4800 MW

[1] Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

Transmission Loss Factors

Transmission Loss Factor to be Applied to Transmission Pursuant to the Southern Intertie Transmission (IS) Rate Schedule

Rate Schedule	Loss Factor
IS-93 B	3.0%

EXECUTIVE SUMMARY

LONG-TERM INTERTIE ACCESS POLICY

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

INTRODUCTION

The Pacific Northwest-Pacific Southwest Intertie began operation in 1968. Congress authorized the construction of the Intertie to provide an additional market for surplus BPA power, thereby providing greater assurance that we would repay the U.S. Treasury for the Federal investments in the Northwest's power system. To the extent there was capacity excess to Federal needs, Congress also intended that the Intertie allow nonfederal utilities in the Northwest and California to take advantage of the diverse load patterns and resource types between the two regions.

The present capability of the Intertie is about 5,200 megawatts (MW), 3,200 MW on the two alternating-current (AC) lines and 2,000 MW on the direct-current (DC) line. Ownership of the Intertie in the Northwest is shared by BPA, Portland General Electric Company (PGE) and Pacific Power & Light Company (PP&L). We provide access to all Northwest generating utilities. Ownership in California is shared by four investor-owned and municipal utilities.

In the early 1980s demand for sales over the Intertie increased dramatically. Nearly every utility in the Northwest had excess power to sell and forecasted a surplus into the next decade and beyond. Northwest utilities frequently filled the Intertie with nonfirm energy and sought to negotiate long-term transactions with California. Prior to 1984 and the implementation of the Interim Intertie Access Policy (IAP), BPA lost significant revenue opportunities by allowing other utilities unfettered access to the Intertie. Combined effects of (1) the Northwest Preference Act, 16 U.S.C. §837, et seq., which gives Northwest utilities a special competitive advantage over us; (2) oversupply conditions in the Northwest; and (3) a restricted market in California due to limited ownership of the Intertie in California caused us to lose sales. We were unable to make our payments to the U.S. Treasury.

In 1984 we implemented the Interim IAP, followed by the Near-Term IAP in 1985. These policies governed access to the Intertie while we developed a Long-Term Intertie Access Policy (LTIAP).

The LTIAP, issued by the Administrator on May 17, 1988, accomplishes the following objectives which have guided us throughout the process:

1. The LTIAP assures BPA of reasonable access to the Intertie to sell both firm and nonfirm energy, thereby enhancing our ability to repay, with interest, $8 billion in Treasury investments.
2. The policy is a reasonable and effective means of safeguarding our $120 million investment in fish and wildlife protection.
3. It balances the competing demands of nonfederal utilities for Intertie access to sell, exchange, or purchase both firm power (through long-term contracts) and nonfirm energy (through the short-term, spot-market).

4. It provides a basis for greater planning certainty to utilities.
5. It allows for efficient use of generating resources in the Northwest and California.
6. It specifically addresses competitive concerns between California and the Northwest.
7. In doing all of the above, it strikes a balance between the Northwest and California, among generating and nongenerating utilities, other BPA customers, environmental interests and Federal taxpayers.

Issuance of this policy culminates our review of comments submitted by over 150 different utilities, regulatory agencies and interest groups. Through a combination of formal, transcribed meetings and informal discussions, we have increased our knowledge of their positions -- and they of ours. We have twice appeared before the U.S. House Subcommittee on Water and Power Resources to answer questions regarding the IAP. Though often cumbersome and lengthy, the process has produced a policy which addresses the demands of all parties.

Balancing interests. We have been put in the difficult position of balancing the competing interests for use of the Intertie. The sum of the demands placed on the Intertie far exceeds the facility's ability to meet them.

Our total-requirements customers insist that BPA should protect its revenues in order to maintain stable power rates and to repay the U.S. Treasury in a timely manner. They suggest that BPA should allocate firm and nonfirm Intertie access to itself first, always assuring that BPA would be able to sell its surplus power. Northwest generating utilities seek a policy which allows sufficient and assured access for their own firm and nonfirm sales. California parties generally argue for a policy which allows them unconstrained access to inexpensive Northwest and Canadian resources. Environmental organizations support a policy that would prevent the Intertie from encouraging development that would harm fish and wildlife resources.

Our main concern in reaching this balanced policy has been reconciling BPA's need to meet its fiscal obligations with these other competing demands for use of the Intertie. While BPA has the discretion to implement the "Federal-first" policy supported by our full requirements customers, the LTIAP instead provides significant access to nonfederal utilities for a variety of transactions while protecting BPA from revenue shortfalls.

It is not reasonable to suggest, as California commenters did in the public process, that BPA incur revenue losses to be recovered through rate increases to its total-requirements customers. These customers have a strong statutory argument -- explained in the decision -- that we should adopt a Federal-first policy to maximize Federal sales over the Intertie. By rejecting Federal-first, we incur an obligation to provide these customers with rate stability through alternative means. First among these alternative protections is the reservation of Intertie capacity for BPA sales.

If the revenue-protective measures adopted in the LTIAP prove unworkable or unduly controversial, the obvious remedy is not more access for nonfederal utilities. Instead, it is Federal-first.

FORMULA ALLOCATION

The Intertie accomodates transactions in two distinct markets. Sellers of power to California sell in two distinct markets, one for long-term transactions and one for short-term sales. Formula Allocation in the LTIAP refers to Intertie capacity made available for short-term sales of energy. We have taken a hard look at Formula Allocations as it has been one of the most hotly debated issues throughout the LTIAP's development.

The LTIAP continues the basic Formula Allocation method used in the Near Term Intertie Access Policy (NTIAP) of allocating access to the Intertie based on three possible conditions. We have changed the specifics of each Condition to reflect criticisms and suggestions made on the two LTIAP drafts. Provisions for Conditions 2 and 3 address directly the contentious anti-competitive concerns between California and the Northwest.

Condition 1. Condition 1 under the NTIAP incorporated the pre-existing Exportable Agreement, which expires on December 31, 1988. Parties to the agreement declare amounts of surplus energy available for export at the applicable BPA rate. If total declarations of exportable energy exceed the available Intertie Capacity or the size of the Pacific Southwest market, whichever is smaller, each party to the agreement is allocated access to the smaller amount based on its share of total declarations.

The 1986 draft LTIAP proposed that upon expiration of the Exportable Agreement a condition of spill or likelihood of spill on the Federal Columbia River Power System (FCRPS) would trigger Condition 1. BPA and Northwest Scheduling Utilities could declare surplus energy available for export and BPA would allocate access to the Intertie based on the ratio of each declaration to the sum of all declarations multiplied by the available Intertie Capacity. Each Scheduling Utility's allocation would be limited by the ratio of its regional hydroelectric capacity to the total regional hydroelectric capacity of the Scheduling Utilities multiplied by the total of all declarations (the "Hydro Cap").

We received comments on the 1986 draft which led us to revise Condition 1 to mirror the Exportable Agreement more closely. Under the 1987 draft a condition of spill or likelihood of spill on the FCRPS determined Condition 1. BPA and Scheduling Utilities could declare surplus energy available for export at the applicable BPA rate and receive a share of available Intertie Capacity based on the Hydro Cap. To the extent that the market for Northwest energy at BPA's price was less than the available Intertie Capacity, we allocated access to the Intertie to equal that market.

Generally, commenters on the 1987 draft did not argue against Condition 1 per se. They focused instead on its specific provisions. The bulk of the comments were directed at the Hydro Cap and at allocating Intertie capacity based on the size of the California market rather than the size of the Intertie capacity. In response to concerns heard at the public meetings in January 1988, we proposed an alternative Condition 1 allocation method. The LTIAP adopts this recent proposal.

The True-Up. The market for power in California is often less than the available Intertie capacity because of minimum generation requirements in California. As the Intertie is expanded and Southwest utilities bring on new generation that cannot be displaced with spot-market purchases, the frequency of this situation is likely to grow.

The 1987 draft allocated Intertie capacity based on the size of the California market as a protection against revenue shortfalls. Analyses indicated that we would lose approximately $16.4 million in 1989 by allocating to the Intertie rather than the market. This loss would decrease to $10.7 million in fiscal year 1992. Beyond 1992 the difference would increase, mainly due to projected fuel price increases.

The heart of the revenue problem is the Northwest Regional Preference Act, 16 U.S.C. 837, et seq., which requires BPA to quote an energy price to Northwest utilities before making any sale to the Southwest. This creates a problem in which Northwest utilities, which are BPA's competitors, know our price -- but we do not know their prices. In Condition 1, where the size of the Southwest market is less than available Intertie Capacity, Northwest utilities are able to use this information to undercut the BPA price and use their allocations to reduce BPA's hourly sales to a small Southwest market. If a "real-time" BPA pricing iteration were even possible, we would still be required to announce our new price to the Northwest. Regional preference makes BPA a "sitting duck" for its competitors.

Allocating according to the California market size would reduce BPA's vulnerability by reducing the size of Scheduling Utility allocations. This provision came under attack, however, from both California and Northwest parties. The alternative discussed at the January 27 public meeting seemed to allay concerns regarding BPA's market control. No one disputes that the Regional Preference Act causes BPA a revenue dilemma, especially at times when we face spill on the hydro system. The true-up alternative is the least intrusive remedy.

The Hydro Cap. Both the 1986 and 1987 LTIAP drafts allocated Intertie capacity based on a utility's hydroelectric capability. The logic for the Hydro Cap was that when the Federal system is spilling or likely to spill, the maximum allocation to utilities with greater hydroelectric resources would increase, thus decreasing the probability of wasting the resources by spilling. Under this provision, BPA's share of allocations would tend to increase due to its large hydroelectric capacity.

Much of the debate over the Hydro Cap focused on two issues. First, removing the Hydro Cap could cause hydro-based utilities to spill. Second, without the Hydro Cap, utilities could "overdeclare" by including uneconomic combustion turbines in their declarations with no intent of ever operating them.

Discussion at the January meetings helped resolve these concerns. When the Federal hydro system faces spill, other systems might not always be in the

same condition. The Hydro Cap could give disproportionately large shares of Intertie Capacity to hydro-based utilities when they may not face a threat of spill, while frustrating the marketing activities of utilities with hydro and thermal resources. Furthermore, several utilities and BPA indicated that if a utility is facing spill with insufficient access to market the available energy on the Intertie, such energy could generally displace Northwest thermal generation.

Several factors would help deter overdeclarations. First, the take-or-pay feature of our IS-87 transmission rate requires a utility to pay for its allocation whether or not it is used. Second, BPA monitors declarations and is aware of each utility's resources and capabilities. We have not observed significant overdeclarations under past policies. Third, from time to time we can request documentation on each utility's declaration as a further insurance against abuse.

Conditions 2 and 3. Allegations of anti-competitive practices on both the northern and southern portions of the Intertie were made during the debate over Formula Allocations. California commenters argue that pro-rata allocations to nonfederal utilities under the LTIAP would tend to stabilize prices at levels higher than those at which sellers might increase their total sales by reducing prices. The Northwest just as logically concludes that pro-rata allocations of California Intertie capacity suppress prices below levels that would prevail in a market where more buyers independently bid for Northwest energy.

We recognized that in implementing a long-term policy we must try to resolve this issue to meet the goals outlined for the LTIAP. We therefore proposed in section 5(d) of the 1987 draft LTIAP to cease pro-rata allocations to non-Federal utilities under Conditions 2 and 3 after completion of the third AC Intertie, provided anti-competitive problems in the Southwest were cured by that time. This proposal was discussed extensively during the public meetings in January 1988 and again in comment letters, mainly from California parties. The final LTIAP takes this proposal a step further. Section 5(d) now ceases pro-rata allocations under Conditions 2 and 3 for an 18-month experimental period.

We will analyze the success or failure of the experiment throughout its term. We will be particularly concerned about the removal of restrictions on California's portion of the Intertie. Utilities, regulators, and other interested parties will be encouraged to express their views in writing and through informal discussions. At least 30 days before the experiment ends, we will issue a written report on whether to continue the experiment.

The experiment will work as follows. Under Condition 2, when the declarations of BPA and Northwest utilities exceed Intertie capacity, we will make a pro-rata allocation to BPA and leave the remaining block of Intertie capacity available to Northwest utilities as a whole. Each Northwest utility could then compete to make sales to Southwest utilities, with no assurance of any individual allocation. Under Condition 3, when the declarations of BPA

and Northwest utilities are less than Intertie capacity, BPA will receive an allocation equal to its declaration and Northwest utilities will receive a block allocation equal to the sum of their declarations. After regional utilities, U.S. extraregional utilities and then Canada have access to remaining Intertie capacity. During Condition 3, we expect significant competition whenever the size of the California market is less than Intertie capacity.

Until the experiment is in effect, Conditions 2 and 3 are similar to those in the NTIAP and the two LTIAP drafts.

The LTIAP retains pro-rata allocations under Condition 1. Allocation under Condition 1 appears to be of less concern to California commenters than allocation during other conditions. Alternative Formula Allocation proposals recognized the importance of pro-rata allocations when the Northwest faces spill conditions. Retention of Condition 1 allocations will (1) help assure nonfederal utilities of Intertie access when hydrological conditions might otherwise force them to spill, and (2) provide an enforcement mechanism for the Protected Area provisions described below.

Some commenters have suggested that we allow access to Canadian utilities equal to that of Northwest utilities. The courts, however, have upheld our policy that capacity excess to our needs must be provided on a fair and nondiscriminatory basis first to Northwest utilities. If the Free Trade Agreement between Canada and the United States now being considered in Congress and the Canadian parliament is implemented, the distinction between U.S. extraregional utilities and Canadian utilities will no longer be made.

ASSURED DELIVERY

Utilities seek firm access to the Intertie for long-term transactions. The LTIAP refers to this kind of access as Assured Delivery. The earlier NTIAP did not provide for Assured Delivery service.

Amount. The final LTIAP reserves 800 MW for Assured Delivery transactions. This is an increase from the 420 MW reserved in the 1986 draft. BPA lost $213 million in fiscal year 1987; we do not want to exacerbate this problem with the final LTIAP. Given these uncertainties, we are cautious about committing major portions of the Intertie for long-term nonfederal use.

Yet, the 800 MW upper limit in itself is a fairly dramatic departure from the past. It will facilitate a greater number and variety of firm transactions than before. Our studies indicate an annual revenue loss of approximately $9 million in lost nonfirm revenue and displaced firm power sales to our public agency customers. The revenue effects on BPA have been quantified further in a study by the PNUCC. These adverse revenue effects, offset by mitigation measures discussed below, have been found acceptable by a fairly broad cross-section of commenters.

In the public meeting and comment letters, most parties seemed satisfied with the 800 MW if we were to consider increasing it upon completion of the third AC project. BPA will reassess the 800 MW limit upon commercial operation or termination of the project.

Exhibit B Allocations. As for the limits on types of transactions, BPA is convinced of the wisdom of imposing limitations on firm power sales. These limits are shown in Exhibit B of the LTIAP. From the standpoints of environmental quality and financial risks, it seems appropriate to limit Assured Delivery capacity to the amount of firm surplus presently available in the Northwest for export sales. In a change from the 1987 draft policy, the LTIAP provides that Scheduling Utilities may use their individual Exhibit B amounts for sales or exchanges.

The final LTIAP does not allocate the remaining 356 MW of Assured Delivery capacity among Scheduling Utilities. That amount will be available for exchange transactions of Scheduling Utilities on a first-come, first-served basis.

We have reached agreement (or agreement in principle) covering 341 MW of Assured Delivery service. Agreements include a 20-year 105 MW firm power sale from Montana Power Company to Los Angeles Department of Water and Power; a 41 MW firm power sale from Tacoma City Light to Western Area Power Administration (WAPA); a 45 MW firm power sale from Longview Fibre/Cowlitz County Public Utility District to WAPA; and a 20-year 150 MW seasonal exchange between The Washington Water Power Company and Pacific Gas and Electric Company. Each of these agreements accommodates our lost revenue concerns differently.

To allow for maximum use of the Intertie, a utility granted Assured Delivery may shape its firm power sale into the months of September through December by delivering up to 1.8 times its Exhibit B amount. During those fall months, spot market energy sales to the Southwest tend to be less than in the spring when the region's hydroelectric dams are more often near or in a spilling condition. If a utility shapes Assured Delivery energy into the fall, less firm energy may be shaped into remaining months of the operating year so that the total energy delivered does not exceed its annual Exhibit B energy maximum for firm sales.

BPA will also continue to work with Nonscheduling Utilities to provide the opportunity to sell the output of their generating resources over BPA's Intertie capacity.

Mitigation. Mitigation refers to conditions imposed on a utility for an Assured Delivery contract. Intertie Capacity not available to BPA because of Assured Delivery contracts executed between a Northwest utility and a Southwest utility can reduce BPA revenues and inhibit BPA's ability to make its Treasury payments. During the operating year BPA often has power available to fully load the Intertie. Assured Delivery granted under these circumstances would reduce BPA's revenues, thereby putting at risk our ability to meet our obligations to the Treasury.

This fiscal concern is in potential conflict with the policy objective underlying the 800 MW of Assured Delivery -- assisting Northwest utilities in disposing of their surpluses by means of long-term firm power sales to the Southwest. Strong objection was received from our Priority Firm Power customers to our absorbing the entire cost (lost revenues) of these transactions and the subsequent passing of the costs to them in increased rates. California and Northwest generating utilities generally tend to agree that some form of mitigation is due BPA. They question the level of compensation and what provisions for mitigation should be included in the LTIAP.

The 1986 draft of the LTIAP allowed Assured Delivery without regard to the adverse impacts on BPA's ability to sell firm power or nonfirm energy. Both the 1987 draft and the LTIAP impose mitigation upon utilities with Assured Delivery contracts. The mitigation provisions in the LTIAP provide only partial compensation for the revenue impacts resulting from transactions, but provide sufficient assurance that these transactions over the Intertie will not harm our revenue recovery.

It would be a false precision to claim that we could develop mitigation measures that offset dollar-for-dollar the losses projected in any 20-year study. Assumptions about annual rainfall, gas prices, aluminum prices, and load growth make this exercise judgmental. With this limitation in mind, the LTIAP incorporates the following mitigation provisions.

One mitigation measure requires that during any hour in which prescheduled energy sales are made under Condition 1 and Condition 2 Formula Allocation

procedures, a utility must deduct its Assured Delivery amount from its Formula Allocation amount. The total amount of Intertie access granted to each utility is equal to its Formula Allocation. If a utility's Assured Delivery amount is greater than its Formula Allocation, then that utility must purchase enough energy from BPA or, during Condition 1, other Northwest utilities to make up the difference. This mitigation measure will partially offset the spot-market revenues BPA will lose by granting Assured Delivery.

Under the other mitigation measure, if BPA has invoked Condition 1 or Condition 2 Formula Allocations, cash out provisions of exchange contracts become inoperative. Cash outs allow a Northwest utility to accept dollar payments from a Southwest utility in lieu of actual energy returns. Prohibiting these during Conditions 1 and 2 has the effect of increasing the north-to-south capability of the Intertie when energy is being returned and increasing the size of the market for BPA and Scheduling Utility sales.

The draft LTIAP required energy returns under seasonal exchanges to the California/Oregon border (COB) or the Nevada/Oregon border (NOB). This was initially included in the mitigation provisions for seasonal exchanges. However, BPA needs the certainty of available capacity resulting from return requirements at COB/NOB. For this reason, the final LTIAP includes this provision as a standard requirement for all exchanges rather than considering it a mitigation measure.

The LTIAP also allows utilities the opportunity to negotiate individual packages of mitigation in addition to the LTIAP's stated mitigation provisions. Such case-by-case mitigation packages could be a combination of the above mitigation provisions or could include beneficial arrangements for BPA that have not been addressed in this policy. Our main concern in any mitigation package is recovery of any spot-market revenue losses, but we will also be looking at the operational impacts of any proposal.

Extraregional Access. Provisions in the 1987 draft for firm transactions by extraregional utilities required that the utility must provide some benefit to BPA, such as increased storage, improved system coordination or operation, or other consideration of value. In addition, the utility must agree to the mitigation provisions of the policy. Canadian utilities were required to wait for access until after the Intertie was rated at 7900 MW.

In reconsidering this provision we saw no reason for denying Canadian utilities access for firm transactions until after the Intertie is upgraded to 7900 MW if Canadian utilities are willing to provide increased coordination or other items of value. This provision of limiting Canadian access to after an upgrade of the Intertie has been deleted from the LTIAP.

As with Formula Allocation, BPA anticipates that if the Free Trade Agreement is passed the distinction between U.S. extraregional utilities and Canadian utilities will no longer exist.

FISH AND WILDLIFE PROTECTION

Protected Areas. The LTIAP prohibits Intertie access for new hydro projects licensed within "protected areas" -- river reaches withdrawn from hydro development due to the presence of wildlife or anadromous and high-value resident fish. BPA also has designated areas where we have determined that investments in habitat, hatchery, passage, or other projects may result in the presence of anadromous fish. The Northwest Power Planning Council (Council) has proposed a protected area program that covers the entire Northwest. BPA's designations, however, cover only the Columbia River basin.

Our focus is on hydro developments which will frustrate our investments made in the region to achieve the goals of the Council's Fish and Wildlife Program. The LTIAP ensures that those expenditures and existing productive habitat will not be harmed by future hydro developments. BPA has designated protected areas by using information collected through the Council's Hydro Assessment Study.

Under the LTIAP, we will consider the Council's final protected area program or any revisions the Council may include in the future. We will also consider appropriate state comprehensive river plans. The policy should effectively eliminate utilities' fears that they never know with certainty whether a hydro resource will qualify, or continue to qualify, for access to the Intertie.

The LTIAP does not necessarily prevent hydro development in protected areas. However, the protected area provisions will send an unambiguous, self-enforcing message to FERC, other regulators, and hydro developers that no Intertie access will be provided for projects constructed in areas of greatest concern to BPA and the Council.

Enforcement. If a Scheduling Utility proceeds to acquire a license or purchase power from a hydro project developed in a protected area, BPA will reduce the amount of that utility's power transmitted over the Intertie during Condition 1. Depending upon the size of the project, the reduction may affect both Assured Delivery and Formula Allocations. These reductions will take place regardless of whether power from the protected area project is actually transmitted on the Intertie. There is no need to trace power flows from a protected area resource.

Projects not affected by the Policy. For all hydro projects not affected by BPA's protected area designations, BPA will intervene in FERC proceedings if we determine that projects -- new or existing, inside or outside the Columbia Basin -- pose significant threats to our fish and wildlife responsibilities.

The provisions do not affect hydro projects licensed before the effective date of the policy. While we recognize a potential for existing projects to harm BPA fish and wildlife investments, we do not believe there is sufficient evidence to indicate that those projects are presently operating contrary to

the Council's Fish and Wildlife Program or that the Council has been unable or unwilling to implement Program measures through the FERC process. Measures affecting existing projects in the Council's Program are explicitly directed to FERC and state agencies for implementation.

We have provided a limited procedure to provide access to the Intertie in the case of a project a developer believes will contribute to the Council's Fish and Wildlife Program and BPA investments. However, our decision to provide access relies on a clear demonstration of the benefits and a regional consensus.

Finally, the LTIAP creates a limited exception for Protected Area projects that an investor-owned utility might be forced to acquire under PURPA. To qualify, however, the affected utility must pursue all legal remedies available to avoid purchasing the Protected Area project output.

LONG-TERM INTERTIE ACCESS POLICY

GOVERNING TRANSACTIONS OVER FEDERALLY OWNED
PORTIONS OF THE
PACIFIC NORTHWEST-PACIFIC SOUTHWEST INTERTIE

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

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FINAL LONG-TERM INTERTIE ACCESS POLICY

Section 1. **Definitions**

1. "Administrator" means the Administrator of Bonneville Power Administration (BPA) and is used interchangeably with BPA.

2. "Administrator's Power Marketing Program" refers to all marketing actions taken and policies developed to fulfill BPA's statutory obligations. These actions and policies are based on exercises of authority to act, consistent with sound business principles, to recover revenue adequate to amortize investments in the Federal Columbia River power and transmission systems, while encouraging diversified use of electric power at the lowest practical rates. In the Northwest, the Administrator's Power Marketing Program covers BPA's obligations to provide an adequate, reliable, economical, efficient, and environmentally acceptable power supply, while preserving public preference to Federal power. In the Southwest, the Administrator's Power Marketing Program covers activities to market surplus Federal power at equitable prices, while preserving regional and public preference to Federal power, and to assist in marketing Northwest nonfederal power.

3. "Allocation" means the share of the Intertie Capacity made available for short-term sales of energy.

4. "Assured Delivery" means firm transmission service provided by BPA under a transmission contract to wheel power covered by a contract between a Scheduling Utility and a Southwest utility. Assured Delivery contracts may not exceed 20 years in duration. The service is interruptible only in the event of an uncontrollable force or a determination made pursuant to sections 7 or 8 of this policy.

5. "Available Intertie Capacity" is defined as the physically available capacity controlled by BPA, reduced by the capacity reserved under Section 2 of this policy, and the capacity necessary to satisfy Assured Delivery contracts not subject to operational mitigation requirements under this policy.

6. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts; and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act.

7. "Exchange" refers to various types of transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power, at prespecified delivery rates, from North to South during the Southwest's peak demands and returns of capacity and/or energy from South to North during other times. Transactions vary depending on the lag between deliveries and returns. A "naked capacity" transaction might require off-peak energy returns within 24 hours, whereas a seasonal exchange might call for firm power returns within 6 months.

8. "Extraregional Utilities" are generating utilities, or divisions thereof, that do not provide retail electric service and do not own or operate significant amounts of generating capacity in the Northwest.

9. "Formula Allocation" means the process by which Intertie Capacity made available for short-term sales of energy.

10. "Intertie" means the two 500-kv alternating current (AC) transmission lines and one 1000 kv direct current (DC) line, which extend from Oregon into California or Nevada, and any additions thereto identified by BPA as Pacific Northwest-Pacific Southwest Intertie facilities.

11. "Intertie Capacity" means the North to South transmission capacity of the Intertie controlled by BPA through ownership or contract; increased by power scheduled South to North, decreased by loop flow, outages, and other factors that reduce transmission capacity; and further decreased by Pacific Power & Light Company's schedules, under its scheduling rights at the Malin substation (BPA Contract Nos. DE-MS79-86BP92299 and DE-MS79-79BP90091).

12. "Mitigation" refers to the requirements imposed by BPA on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's firm power transaction, that inhibit BPA's ability to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless a scheduling utility either agrees to a specially designed charge or negotiates substitute measures with BPA on a case-by-case basis.

13. "Nonscheduling Utility" means a nonfederal Northwest utility that owns a Qualified Northwest Resource, but does not operate a generation control area within the Pacific Northwest. A Nonscheduling Utility requesting Intertie access for its resource must do so through the Scheduling Utility (or BPA) in whose control area the resource is located.

14. "Pacific Northwest" (or "Northwest") is defined in the Northwest Power Act, 16 U.S.C. §839e, as the states of Oregon, Washington, and Idaho; the portion of Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and any contiguous service territories of rural electric cooperatives serving inside and outside the Pacific Northwest, not more than 75 air miles from the areas referred to above, that were served by BPA as of December 1, 1980.

15. "Protected Area" means a stream reach within the Columbia River drainage basin specially protected from hydroelectric development because of the presence of anadromous or high value resident fish, or wildlife. Protected areas may also include stream reaches which could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

16. "Qualified Extraregional Resource" means:

(a) a generating unit located outside the Northwest that was in commercial operation on the effective date of this policy. However, the term excludes portions of units covered as Qualified Northwest Resources.

(b) after BPA has determined that the capacity of the Intertie is rated at approximately 7,900 MW, all resources located outside of the Northwest, other than the portions of extraregional resources covered as Qualified Northwest Resources.

17. "Qualified Northwest Resource" excludes BPA Resources, but includes:

(a) Resources located inside the Northwest that are in commercial operation as of the effective date of this policy.

(b) Scheduling Utility extraregional generating resources dedicated to Northwest loads on the effective date of this policy. This term includes pro rata portions of Montana Power Company's and Pacific Power and Light Company's shares of the Colstrip No. 4 generating station, based on the ratio of their respective regional loads to their respective total loads; and Idaho Power Company's share of Valmy No. 2.

(c) New regional resources of Scheduling Utilities, except for hydroelectric resources located in Protected Areas.

18. "Resource" means an electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

19. "Scheduling Utility" means the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The term excludes Utah Power & Light Company, either as a separately owned company or as a division of another corporation, which has sufficient transmission capacity to the Southwest without access to the Federal Intertie.

20. "Seasonal Exchange" means a transaction that takes advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power, at a prespecified delivery rate, from North to South during the Southwest's summer load season and from South to North during the Northwest's winter load season. Seasonal Exchanges may involve payments of additional consideration to reflect the relative seasonal values of power throughout the western United States. Seasonal Exchange schedules of Northwest utilities will be referred to as "deliveries," and schedules of Southwest utilities will be referenced as "returns." A Scheduling Utility must be able to support its summertime firm power deliveries with generating resources that are surplus to its Northwest requirements. The sum of a Scheduling Utility's energy resources for each month in which deliveries are made (with special concern for August) must exceed its corresponding Northwest loads by an amount sufficient to support the Seasonal Exchange.

21. "Section 9(i)(3) resource" means a Scheduling Utility resource that BPA has granted priority in receiving BPA transmission, storage and load factoring services as defined in §9(i)(3) of the Northwest Power Act.

Section 2. **Intertie Capacity Reserved for BPA**

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) transmit all of BPA's surplus firm power and to serve other obligations,

(b) perform obligations, including, but not limited to, the existing transmission contracts listed in Exhibit A, to the extent such obligations differ from the conditions specified in this policy,

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit B to this policy, and

(d) satisfy BPA firm obligations, that have not been prescheduled, by using unutilized portions of Formula Allocation amounts.

Section 3. **Conditions For Intertie Access**

(a) All Intertie access will be granted pursuant to the conditions and procedures of this policy, unless otherwise specified in the three existing BPA transmission contracts listed in Exhibit A.

(b) BPA will provide Intertie access only for BPA Resources and the Qualified Northwest Resources of Scheduling Utilities, except to the extent that Qualified Extraregional Resources are permitted access under this policy.

(c) BPA will provide Assured Delivery and allocate remaining Intertie Capacity when providing such access will not substantially interfere with operating limitations of the Federal system. Examples of these limitations, which reflect BPA's obligation to operate in an economical and reliable manner consistent with prudent utility practices, include:

(1) The BPA Reliability Criteria and Standards,
(2) Western Systems Coordinating Council minimum operating reliability criteria,
(3) North American Electric Reliability Council Operating Committee minimum criteria for operating reliability, and
(4) coordination agreements among BPA, scheduling utilities and other Federal agencies regarding resource and river operations.

(d) Any utility that has contractual or ownership rights to Pacific Northwest-Pacific Southwest Intertie capacity or to other transmission lines to California or the Southwest market must fully utilize such capacity prior to receiving any access to BPA's Intertie Capacity. If a Scheduling Utility with Intertie rights needs BPA Intertie Capacity to reach a particular Southwest utility, BPA will consider negotiated swaps of capacity to accommodate such requests.

Section 4. **Assured Delivery for Intertie Access**

Subject to the limitations and other conditions in this section and in other sections of this policy, BPA has determined that it can provide limited Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) **General Provisions**

(1) **Existing Transmission Contracts.** BPA will provide Assured Delivery for the remaining terms of the firm power sale and Seasonal Exchange contracts identified in Exhibit A to this policy.

(2) **Utilities Owning Or Controlling Southwest Interconnections.** Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. Except for transactions covered by section 4(b) of this policy, a utility with capacity on an intertie, through contract or ownership, must utilize all such capacity on a firm basis before receiving any Assured Delivery.

(3) **Nature Of Transactions.** BPA will not provide Assured Delivery for transactions which a Scheduling Utility cannot demonstrate to be other than an advance arrangement to sell nonfirm energy.

(4) **Waiver Of BPA Service Obligation.**

(A) **Hydroelectric Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest hydroelectric energy shall provide, under 16 U.S.C. §837b(d), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided .

(B) **Thermal Resources.** Assured Delivery contracts that facilitate the export disposition of Northwest thermal energy shall provide, under 16 U.S.C. §839f(c), for a reduction of BPA's power sale contract obligation the Northwest utility, for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided. Such reduction shall become effective at the time BPA determines that it has reached energy load/resource balance, or at a date as specified in the Assured Delivery contract.

(5) **Exchange Contracts.** Exchange contracts must specify that all return energy be scheduled to either the AC Intertie point of interconnection at the California-Oregon border ("COB") or the DC Intertie point of interconnection at the Nevada-Oregon border ("NOB"). Exchange contracts must also specify prescheduled determinations of hourly energy returns.

(6) **Satisfying Requests For Assured Delivery.** All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made.

(b) **New Transactions Not Subject To Capacity Limits**

(1) **Joint Ventures.** Joint ventures between BPA and utilities, such as firm displacement contracts, which allow BPA to increase its sales of surplus power qualify for Assured Delivery.

(2) **Sales In Lieu Of Exchanges.** BPA may offer to satisfy Scheduling Utility demands for Seasonal Exchanges by selling them incremental amounts of surplus firm power during winter months. Upon committing to purchase such incremental firm power at negotiated prices that reflect BPA's

lost opportunities for summer sales, a Scheduling Utility will qualify for Assured Delivery (with mitigation) to wheel an equal amount of firm capacity and energy over the Intertie during summer months.

(3) **Conditions**. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(b)(1) and 4(b)(2). Relevant contracts must be presented for review when Assured Delivery is requested. BPA will satisfy a request within 60 days after a Scheduling Utility has demonstrated satisfaction of the requirements of this policy.

(c) **Transactions Subject To Capacity Limits Under This Policy**

(1) **Maximum Amounts Of Assured Delivery**. BPA will provide 800 MW of Assured Delivery for firm power sales and Exchanges identified in this policy. BPA will reassess the amount of Assured Delivery capacity when the 3d AC Intertie project is either completed or abandoned. Moreover, the 800 MW amount may be subject to some reduction if the DC Terminal Expansion project is not completed on schedule.

(2) **Exhibit B amounts**.

(A) **Current maximum**. Each Scheduling Utility's maximum Assured Delivery amount for firm sales equals its average firm energy surplus, shown in Exhibit B to this policy. BPA will reserve capacity equal to each Scheduling Utility's Exhibit B allocation subject to section 4(c)(2)(D) below. Except for Montana Power Company (MPC), Tacoma City Light, and Cowlitz County Public Utility District, Exhibit B represents projected Scheduling Utility surpluses for the 1988-89 operating year. In satisfaction of all obligations to MPC under Northwest Power Act section 9(1)(3), MPC's Exhibit B amount is set at 105 MW to facilitate long-term sales of firm power from its share of the Colstrip No. 4 coal-fired generating station. Exhibit B amounts for Tacoma and Cowlitz are increased to accommodate existing firm power transactions.

(B) **Shaping**. Firm power sales eligible for Assured Delivery may be shaped within the following ranges. During the months of September through December, a Scheduling Utility may deliver firm energy at a rate up to 1.8 times its Exhibit B average firm surplus amount. During the months of January through August, a Scheduling Utility may deliver firm energy at a rate no greater than 1.0 times its Exhibit B amount. However, total delivered energy may not exceed the Exhibit B annual firm energy maximum.

(C) **Other uses of Exhibit B amounts**. BPA will not entertain Assured Delivery requests for firm power sales in excess of a utility's Exhibit B maximum. However, a Scheduling Utility may use any portion of its Exhibit B maximum, not used for firm power sales, for exchange transactions supported by Qualified Northwest Resources.

(D) **Future changes**. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount will be revoked if, upon revision, a utility's individual Exhibit B amount has declined or if a utility has sold firm power to another utility seeking to increase its Exhibit B

average firm surplus amount. A Scheduling Utility may increase its individual Exhibit B amount by purchasing surplus firm power from BPA or any Scheduling Utility with an Exhibit B amount.

(3) **Other Capacity**. The remaining capacity available for Assured Delivery under this policy is offered to Scheduling Utilities, on a first-come, first-served basis, for Exchange transactions supported by Qualified Northwest Resources. When section 4(c)(2)(D) of this policy is implemented to reduce the Exhibit B maximum of any Scheduling Utility, the reduction will be added to the capacity made available under this provision. Any utility with an Exhibit B amount must exhaust such capacity before requesting Assured Delivery under this provision.

(d) **Mitigation**

(1)**Operational Mitigation**

(A) **Southbound deliveries**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures to preschedule energy deliveries, each utility's Assured Delivery amount shall be deducted from its formula allocation to determine its share of energy scheduled on the Intertie. If the remainder is negative for a given utility, then that utility must make up the difference by purchasing sufficient energy as follows:

(i) during Condition 1 from BPA or any Scheduling Utility with a Formula Allocation during that hour;

(ii) during Condition 2 from BPA, however, if BPA is not in the market the utility may purchase sufficient energy from any other utility.

(B) **Northbound returns**. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures, a utility may utilize the cash-out provisions of an Exchange contract only by reducing one-for-one the amount of North-to-South Intertie capacity otherwise available to it under this policy. The rate of cash out during any condition shall not exceed the rate at which the exchange return could have been scheduled.

(2) **Negotiated mitigation**. A Scheduling Utility may also elect to negotiate with BPA on a case-by-case basis a package of mitigation measures involving mutually agreeable consideration of value commensurate with the service provided.

Section 5. **Formula Allocation Methods**

(a) **Limits On Intertie Capacity Available For Formula Allocation**. Generally, BPA will determine Intertie Capacity available for Formula Allocations after first taking into account the amount of Intertie Capacity necessary to satisfy requirements of the Administrator's Power Marketing Program, existing transmission contracts listed in Exhibit A, and Assured Delivery contracts executed by BPA pursuant to this policy. However, in determining Available Intertie Capacity during Condition 1, BPA will not consider the Assured Delivery contracts to the extent they are subject to operational mitigation requirements. BPA may reduce any allocation, if additional Intertie Capacity is required to minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.

(b) **Protected Area Decrements.** Except as provided in section 4(d)(2)(A) of this policy, BPA will reduce each Scheduling Utility's allocation by any Protected Area decrement imposed pursuant to section 7(d).

(c) **Allocation Methods.**

(1) **Condition 1**

(A) **Until December 31, 1988.** Intertie Capacity will be allocated pursuant to the Exportable Agreement (BPA Contract No. 14-03-73155), when applicable.

(B) **After December 31, 1988.** Condition 1 will be in effect when the Federal hydro system is in spill or there is a likelihood of spill, as determined by BPA. Available Intertie capacity will be allocated pursuant to the following procedure:

(i) Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective declarations to total declarations, multiplied by the Available Intertie Capacity.

(ii) During Condition 1, whenever BPA is unable to utilize its full pro rata share of intertie usage BPA will take larger allocations on ensuing days until the difference in pro rata intertie usage is eliminated.

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, Formula Allocations for BPA and each Scheduling Utility will approximate, by hour, the ratio of each declaration to the sum of all declarations, multiplied by the available Intertie capacity.

(B) If BPA sales drop below 75 percent of its allocation during Condition 2, BPA may take larger allocations on ensuing days until the difference is eliminated.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA and Scheduling Utilities' allocations will equal their declarations. The remaining Intertie capacity will be made available first to U.S. Extraregional Utilities and then to other Extraregional Utilities. Section 3(d) of this policy shall not apply to Scheduling Utilities during Condition 3.

(d) **Formula Allocation Experiment.** BPA is interested in exploring the proposal that it cease making individual Formula Allocations to Scheduling Utilities under Conditions 2 and 3. However, BPA must work with Northwest and Southwest utilities to develop the information capability to accommodate a new scheduling system for nonfederal access. As soon as this can be accomplished BPA will substitute the following provisions for section 5(c) on an 18-month experimental basis:

(1) **Condition 1**

Same as section 5(c)(1).

(2) **Condition 2**

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, the Formula Allocation for BPA will approximate, by hour, the ratio of BPA's declaration to the sum of all declarations, multiplied by the Available Intertie Capacity. The remaining capacity will be made available as a block to Scheduling Utilities. Section 5(c)(2)(B) of this policy shall apply.

(3) **Condition 3**

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA's allocation will equal its declaration. The remaining Intertie capacity will be made available, first, as a block to satisfy the declarations of Scheduling Utilities, second, to U.S. Extraregional Utilities, and third to other Extraregional Utilities. Section 3(d) of this policy shall not apply during Condition 3.

(e) **Data Collection and Evaluation.** Commencing when this policy goes into effect and continuing during the course of the experiment described in section 5(d), BPA will collect information on the following topics relevant to future allocation procedures:

(1) effect on BPA revenue of allocating to nonfederal utilities as a group rather than individually.

(2) impairment of Intertie access for California utilities presently lacking ownership in the southern portion of the Intertie,

(3) any loss of sales to BPA due to a failure to share unused capacity among California entities with ownership or contractual interests in the Intertie,

(4) effects of the experiment on small Scheduling Utilities.

During the course of the experiment, interested parties may submit written comments and recommendations on these issues.

(f) **Findings and conclusions.** At least 30 days before the end of the experiment described in section 5(d), BPA shall publish a report of its findings on the experiment and its decision on whether section 5(d), with possible modification, should be continued as the permanent method of Formula Allocation.

Section 6. **Access for Qualified Extraregional Resources**

(a) **Assured Delivery.** Any request for Assured Delivery of power from a Qualified Extraregional Resource would be granted only by contract which, in addition to the Mitigation measures specified in section 4(d), must include

benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether they would cause substantial interference with the Administrator's Power Marketing Program. An environmental review would also be conducted.

(b) **Formula Allocation**. Under Condition 3, energy from Qualified Extraregional Resources has access to the Intertie. In addition, BPA may provide Extraregional Utilities with Formula Allocation under other conditions, if the utility agrees by contract either to increased participation in the Pacific Northwest's coordinated planning and operation, or to provide other consideration of value, apart from the standard BPA wheeling rate, commensurate with the services provided.

Section 7. **Fish and Wildlife Protection**

(a) **Purpose**. New hydroelectric projects constructed in Protected Areas may substantially decrease the effectiveness of, or substantially increase the need for, expenditures and other actions by BPA, under Northwest Power Act section 4(h), to protect, mitigate or enhance fish and wildlife resources. Intertie access will not be provided to facilitate the transmission of power generated by any new hydroelectric projects located in Protected Areas and licensed after the effective date of this policy. This provision does not apply to added capacity at existing projects.

(b) **Effect**. This section imposes automatic operational limitations on a utility by reducing the amount of energy that can be scheduled over the Intertie, thereby increasing costs or reducing revenues for any utility owning or acquiring the output of a Protected Area hydroelectric resource.

(c) **Implementation**. Protected Area designations for stream reaches in the Columbia River Basin are shown in Exhibit C to this policy. Exhibit C uses Environmental Protection Agency stream reach codes. Subject to review and possible modification, BPA will consider the adoption of comprehensive state watershed management plans and a comprehensive protected area program developed by the Pacific Northwest Electric Power and Conservation Planning Council subsequent to implementation of this policy. BPA will also consider revisions to Protected Area designations if the Council's Program is amended.

(d) **Enforcement**. If a Scheduling Utility or Nonscheduling Utility owns, or acquires the output from, a hydroelectric project covered under the restrictions of section 7(a), BPA will reduce that utility's Formula Allocation by either the nameplate rating of the project (in the case of ownership), or the amount of capacity acquired by contract.

(e) **Exceptions**.

(1) **PURPA Projects**. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an investor-owned utility has been compelled to acquire the output of a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act (PURPA). To qualify for this exception, the investor-owned utility must demonstrate:

(A) that it has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the Protected Area resource in question;

(B) that it has petitioned its state regulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources in recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy;

(C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and

(D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that it was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

(2) **Projects Contributing to Council's Fish and Wildlife Program or BPA Investments**. Access will be automatically denied for projects developed in protected areas unless BPA receives sufficient demonstration that a particular project will provide benefits to existing or planned BPA fish and wildlife investments or the Council's Program. BPA's determination will be based on:

(A) information provided by the project developer, Federal and state fish and wildlife agencies, and tribes; or

(B) action by the Pacific Northwest Power Planning Council.

Section 8. **Other Enforcement Provisions**

(a) Whenever the terms of this policy are not being met, BPA will inform the appropriate utility of the nature of the noncompliance and actions that may be taken to achieve compliance. If noncompliance is not corrected within a reasonable period, BPA may deny access for a resource and refuse to accept schedules.

(b) Upon approval of the proposed U.S.-Canada Free Trade Agreement by the Canadian Parliament and the United States Congress, any and all distinctions made in this policy between Canadian and United States Extraregional Utilities shall terminate on the effective date of the Agreement.

EXHIBIT A
EXISTING AGREEMENTS FOR INTERTIE CAPACITY

This is a list of existing BPA transmission contracts that were signed before the implementation of the NTIAP and will continue to receive Intertie access under the LTIAP.

Utility	BPA Contract No.	Expiration Date
Washington Water Power Company	DE-MS79-81BP90185	07/01/91
Washington Water Power Company	14-03-791101	09/01/88
Western Area Power Administration	DE-MS79-84BP91627	10/31/90

EXHIBIT B
INTERTIE CAPACITY AVAILABLE FOR ASSURED DELIVERY

BPA has reserved 800 MW of Intertie capacity to be available for nonfederal firm transactions. This capacity is allocated as follows:

A. **Average Firm Surplus Allocations:**

UTILITY	AVERAGE MW FIRM SURPLUS	
Chelan County PUD #1	10	
Cowlitz County PUD #1	45	1/
Douglas County PUD #1	0	2/
Eugene Water and Electric Board	14	
Grant County PUD #1	26	
Seattle City Light	23	
Snohomish County PUD #1	0	
Tacoma City Light	41	3/
Idaho Power Company	87	
Montana Power Company	105	4/
Puget Sound Power and Light	0	
Washington Water Power	93	
	444	

NOTE: The Average Firm Surplus (AFS) is directly from the PNUCC Northwest Regional Forecast of March 1987 for the period 1988-89 except as noted below. It includes resources operational on the effective date of this policy. Export contracts are included as loads. Utilities may use their AFS allocations for long term firm sales or for exchanges. Portland General Electric Company and Pacific Power & Light Company are not eligible for an AFS allocation because of their existing interconnections with the Southwest.

1/ Cowlitz Co. PUD's AFS is the amount of their existing export of the Longview Fibre resource. Longview Fibre is considered to be a Federal resource in the Northwest Regional Forecast and is not included under Cowlitz.

2/ Douglas County PUD's AFS is 2; but Douglas has previously requested to show zero.

3/ The amount displayed for Tacoma is the amount of their existing exports displayed in the Northwest Regional Forecast.

4/ Montana Power Company's AFS was increased from 80 MW to 105 MW in settlement of obligations under Northwest Power Act section 9(1)(3).

B. **Intertie Capacity Available for Exchanges:** The above allocations for sales of firm surplus may be used for exchanges. The remaining 356 MW of capacity is available on a first come-first serve basis for exchanges only under the terms of the LTIAP. If there is a decrease in a utility's firm surplus and the utility does not have a contract for that amount, BPA will allocate the difference to capacity available for exchanges by revising this Exhibit B.

EXHIBIT C
PROTECTED AREAS

Exhibit C corresponds to the Northwest Power Planning Council protected area designations within the Columbia Basin, as specified in the Columbia River Basin Fish and Wildlife Program. Stream reaches designated as protected areas are identified by Environmental Protection Agency stream reach codes. Information about designations are contained on hard copy computer printouts or computer diskette copies which are available to the public upon request.

This revision reduces the Transmission Demand from 125 MW to 93 MW on lines C.1.b. and C.2.b. due to implementation of the Capacity Ownership Agreement, Contract No. DE-MS79-95BP94628.

TRANSMISSION PARAMETERS

A. Points of Interconnection.

North-to-South:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV
South-to-North:	COB

B. Points of Delivery.

North-to-South:	COB
South-to-North:	Malin 500 kV Captain Jack 500 kV Alvey 500 kV Summer Lake 500 kV

C. Transmission Demand.[1/]

1. North-to-South Transactions:

a.	01/01/94 to 05/31/94:	75 MW
b.	06/01/94 to 12/31/94:	125 MW
c.	01/01/95 and thereafter:	93 MW

2. South-to-North Transactions:

a.	01/01/94 to 05/31/94:	75 MW x Intertie South-to-North RTC ÷ 4800 MW
b.	06/01/94 to 12/31/94:	125 MW x Intertie South-to-North RTC ÷ 4800 MW
c.	01/01/95 and thereafter:	93 MW x Intertie South-to-North RTC ÷ 4800 MW

1/ Transmission Demands shall be rounded to the nearest whole megawatt, unless otherwise mutually agreed.

D. Description of Points of Interconnection and Delivery.

1. ALVEY SUBSTATION:

Location: the point in Bonneville's Alvey Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Alvey Substation, in the 500 kV circuits over which such Electric Power flows.

2. CAPTAIN JACK SUBSTATION:

Location: the point in Bonneville's Captain Jack Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in Bonneville's Captain Jack Substation, in the 500 kV circuits over which such Electric Power flows.

3. MALIN SUBSTATION:

Location: the point in the Malin Substation, where the 500 kV facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Malin Substation, in the 500 kV circuits over which such Electric Power flows.

4. SUMMER LAKE SUBSTATION:

Location: the point in the Summer Lake Substation where the facilities of Bonneville and PacifiCorp are connected;

Voltage: 500 kV;

Metering: in the Summer Lake Substation, in the 500 kV circuits over which such Electric Power flows.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By _____
Senior Account Executive

Name Patrick G. McRae
(Print/Type)

Date January 11, 1995

PACIFICORP

By _____

Name Jerry D. Miller
(Print/Type)

Title Manager, Power System Services

Date January 23, 1995

(PMLAN-MPSM-W:\PMT\CT\94285c_1.DOC)

AUTHENTICATED

Service Agreement No. 00TX-10367

SERVICE AGREEMENT
for
POINT-TO-POINT
TRANSMISSION SERVICE
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PACIFICORP POWER MARKETING, INC.

1. This Service Agreement, dated as of 11/1/2000, is entered into, by and between the Bonneville Power Administration Transmission Business Line (the "Transmission Provider") and PacifiCorp Power Marketing, Inc. (the "Transmission Customer").

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point ("PTP") Transmission Service under the Tariff.

3. The Transmission Customer has provided to the Transmission Provider an Application deposit, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.

4. Service under this Service Agreement shall commence on 2400 hours on September 30, 2001, and shall terminate on 2400 hours on September 30, 2010.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit B.

7. The Tariff is incorporated herein and made a part hereof.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. Should the Commission, in an order issued pursuant to the Transmission Provider's filing of the Tariff and this Service Agreement for reciprocity purposes, disapprove any provision of this Service Agreement, the parties shall amend the Service Agreement to comply with the Commission's order. The Transmission Provider shall prepare an amendment for execution as soon as reasonably practicable after issuance of the Commission's order.

11. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(I) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Tariff.

IN WITNESS WHEROF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PACIFICORP POWER MARKETING	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C. VAN ALDERWALT	By: /S/ MICHAEL RASCHIO
Name: Peter C. van Alderwerelt *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: Managing Director	Title: Transmission Account Executive
Date: 11-1-00	Date: 10/24/00

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EXHIBIT A
SPECIFICATIONS FOR LONG-TERM
FIRM POINT-TO-POINT TRANSMISSION SERVICE

Not applicable at this time.

EXHIBIT B
NOTICES

1. NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, First Class mail, by telefax or sent by acknowledged delivery.

If to the Transmission Customer:

Contract Administration
PacifiCorp Power Marketing,Inc.
830 NE Holladay, Suite 200
Portland, Oregon 97232
Attention: Jan Wolsleben
Title: Contract Administrator
Phone: (503) 813-5703
Fax: (503) 813-5707

If to the Transmission Provider:

Bonneville Power Administration
P. O. Box 491
Vancouver, WA 98666-0491
Attention: Transmission Account Executive for PacifiCorp Power Marketing - TM-Ditt2
Phone: (360) 418-8695
Fax: (360) 418-8320

2. NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by telefax or sent by First Class mail or acknowledged delivery.

If to the Transmission Customer:

PacifiCorp Power Marketing,Inc.
830 NE Holladay, Suite 200
Portland, Oregon 97232
Attention: Rob Goodman
Title: Mngr, Transaction Trading
Phone: (503) 813-7158
Fax: (503) 813-5700
Attention: Real Time Desk
Phone: (503) 813-5752
Fax: (503) 813-5700

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
TOD-DITT1
Vancouver, WA 98666-0491
Attention: Outage Dispatcher (Dittmer)
Phone: (360) 418-2274 *(outage planning)*
Phone: (360) 418-2281 *(real time)*
Fax: (360) 418-2938
Attention: System Dispatcher (Dittmer)
Phone: (360) 418-2281 *(real time)*
Fax: (360) 418-2938
Attention: Munro Control Center
Phone: (509) 465-1820 *(real time)*
Phone: (509) 466-2409 *(outage planning)*
Fax: (509) 466-2444

3. **SCHEDULING AGENT**

The Transmission Customer has designated the following scheduling agent.

Scheduling Agent
PacifiCorp Power Marketing, Inc.
830 NE Holladay, Suite 250
Portland, Oregon 97232
Attention: Scheduling
Phone: (503) 813-6078
Fax: (503) 813-5700
Attention: Real Time Desk
Phone: (503) 813-5752
Fax: (503) 813-5700

AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

REVISION NO. 3, TABLE 1
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 386501

This Revision No. 3 to Table 1 adds the Klamath Expansion Project as a resource to be integrated at the City of Klamath Falls Cogeneration Project Substation effective December 1, 2002.

1. TERM OF TRANSACTION

Commencement Date: at 0000 hours on October 1, 2001.[1]
Termination Date: at 0000 hours on May 1, 2007.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
City of Klamath Falls Cogeneration Project	City of Klamath Falls Cogeneration Project Substation 500 kV	BPA	95,000[2]	COB 500 kV	BPA	95,000[2]	BPA
Klamath Expansion Project							
Total Reserved Capacity			**95,000[2]**			95,000[2]	

3. POINT(S) OF RECEIPT

City of Klamath Falls Cogeneration Project Substation

Location: tap into Pacificorp's Meridian-Captain Jack on the 500 kV Transmission Line at City of Klamath Falls Co-generation Project Substation;

Voltage: 500 kV.

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[1] This Revision No. 2 to Table 1 of Exhibit A covers the remaining period of this 6-year transaction; the first 5 months are covered under Exhibit C, Revision 1 to Contract No. 99TX-20112, which expires at 0000 hours on October 1, 2001.

[2] Firm Reserved Capacity associated with this reservation shall be contingent upon operation of the Project; transmission will be on a one-for-one basis with the Project's generation level when less than 95 MW.

4. **POINT(S) OF DELIVERY**

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where Bonneville shall make electric power available for the ISO hereunder;

Voltage: 500 kV.

5. **SERVICE AGREEMENT CHARGES**

Service under this Agreement will, in addition to those charges detailed in Exhibit A, be subject to the charges detailed below. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

Transmission Charge: PTP-02 Rate Schedule or successor rate schedules.

6. **REAL POWER LOSS FACTORS**

Real Power Loss Factors are identified in BPA's Open Access Transmission Tariff under Schedule 9.

Exception: A loss factor of 1.5 percent shall be applied to all schedules from the Klamath Falls Point of Receipt to the COB Point of Delivery. The general Loss Factors identified in Schedule 9 of the Tariff shall apply to all other schedules under this Agreement. In no event shall BPA revise the Transmission Customer's IS Loss Factor, as set forth above, to an amount above 1.5 percent prior to October 1, 2003. BPA shall prepare a new Exhibit A incorporating any Revision and the revised Exhibit shall become effective as of the date specified therein.

PACIFICORP POWER MARKETING	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VAN ALDERWERELT	By: /S/ MICHAEL A RASCHIO
Name: Peter C Van Alderwerelt *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: Vice President	Title: Transmission Account Executive
Date: 1/6/03	Date: 12/10/02

AUTHENTICATED

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 5
REQUEST FOR TRANSMISSION SERVICES
The OASIS Assignment Reference Number (ARef) is: 386513

1. TERM OF TRANSACTION

Commencement Date: at 0000 hours on July 1, 2005.
Termination Date: at 0000 hours on July 1, 2006.

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

Delivering Party (Resource)	POR Name & Voltage	POR Control Area	Reserved Capacity (kW)	POD Name & & Voltage	POD Control Area	Reserved Capacity (kW)	Receiving Party
City of Klamath Falls Cogeneration Project	City of Klamath Falls Cogeneration Project Substation 500 kV	BPA	100,000	California Oregon Border 500 kV	California ISO	100,000	California ISO or other parties with rights to receive power at COB
Klamath Expansion Project							
Total Reserved Capacity			100,000			100,000	

3. POINT(S) OF RECEIPT

City of Klamath Falls Cogeneration Project Substation

Location: tap into PacifiCorp's Meridian-Captain Jack on the 500 kV Transmission Line at City of Klamath Falls Co-generation Project Substation;

Voltage: 500 kV.

4. POINT(S) OF DELIVERY

California Oregon Border

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make Electric power available for the Transmission Customer hereunder;

Voltage: 500 kV.

5. SERVICE AGREEMENT CHARGES

Service under this Agreement will, in addition to those charges detailed in Exhibit A, be subject to the charges detailed below. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

Transmission Charge: IS-04 Rate Schedule

Reservation Fee

Within 30 days after the Transmission Customer signs this Table 5 of Exhibit A, the first annual nonrefundable reservation fee of $117,600 shall be paid to the Transmission Provider. For the second and any subsequent reservation fees, the Transmission Provider will bill the Transmission Customer 30 days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS Rates only and does not include either of the two Ancillary Services that the Transmission Customer is obligated to purchase from the Transmission Provider.

6. REAL POWER LOSS FACTORS

Real Power Loss Factors are identified in BPA's Open Access Transmission Tariff under Schedule 9.

Exception: A loss factor of 1.5 percent shall be applied to all schedules from the Klamath Falls Point of Receipt to the COB Point of Delivery. The general Loss Factors identified in Schedule 9 of the Tariff shall apply to all other schedules under this Agreement. BPA has the unilateral right to modify the 1.5 percent loss factor with a 60-day notice to the Transmission Customer. BPA shall prepare a new Exhibit A incorporating any Revision and the revised Exhibit shall become effective as of the date specified therein.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VAN ALDERWELT	By: /S/ MICHAEL A RASCHIO
Name: Peter C. van Alderwerelt *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: Vice President	Title: Transmission Account Executive
Date: 10/27/03	Date: 10/16/03

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EXHIBIT A, TABLE 9
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. 9 adds 42 MW of Intertie transmission demand at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD).

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2006
Termination Date: at 0000 hours on January 1, 2007

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 960250							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	42,000[3]	COB (500 kV)	BPA	42,000	CISO (PPM)

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

---

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $52,836 shall be paid to the Transmission Provider. For the second reservation fee, the Transmission Provider will bill the Transmission Customer thirty days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS rate only and does not include Ancillary Services.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C. VAN ALDERWERELT	By: /S/ BRIAN D ALTMAN
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Brian D. Altman *(Print/Type)*
Title: **Senior Vice President**	Title: Transmission Account Executive
Date: **8/3/04**	Date: **16 July 2004**

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AUTHENTICATED EXHIBIT A, TABLE ~~17~~8

SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. ~~17~~8 (Oasis No. 753) adds 75 MW of intertie transmission demand at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD).

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2006
Termination Date: at 0000 hours on January 1, 2007

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 960248							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	75,000[3]	COB (500 kV)	BPA	75,000	CISO (PPM)

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal

4. POINT(S) OF DELIVERY

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable.

6. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

Not applicable.

7. SERVICE AGREEMENT CHARGES

(a) **Transmission Charge**
PTP-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $88,200 shall be paid to the Transmission Provider. For the second and subsequent reservation fees, the Transmission Provider will bill the Transmission Customer thirty days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the PTP Rate in effect at the time each payment is due. The Reservation Fee is based on the PTP rate only and does not include Ancillary Services.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/S/ PETER VAN ALDERWERELT**	By: **/S/ MICHAEL A RASCHIO**
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Michael A. Raschio *(Print/Type)*
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **6/8/04**	Date: **5/24/04**

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EXHIBIT A, TABLE 10
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. 10 adds 8 MW of Intertie transmission at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD).

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2006
Termination Date: at 0000 hours on January 1, 2007

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 1313745							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	8,000[3]	COB (500 kV)	BPA	8,000	CISO (PPM)

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

---

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal.

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
IS-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Within 30 days after the Transmission Customer signs this Service Agreement, the first annual nonrefundable reservation fee of $8,224 shall be paid to the Transmission Provider. For the second reservation fee, the Transmission Provider will bill the Transmission Customer thirty days prior to their due date. If the deferral or extension of service spans two or more rate periods, the reservation fee will be based on the IS Rate in effect at the time each payment is due. The Reservation Fee is based on the IS rate only and does not include Ancillary Services.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: **/s/ Peter C. van Alderwerelt**	By: **/s/ Thomas M. Noguchi** **for**
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
JE T.N.	
Title: **Sr. Vice President**	Title: Transmission Account Executive
Date: **10/26/04**	Date: **10/13/04**

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EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 11
ASSIGNMENT OF TRANSMISSION SERVICE

This Revision No. 11 reflects an assignment [1] of transmission service under this Service Agreement from the Assignor, Hermiston Power Partnership (HPP), to Assignee, PPM Energy, Inc. (PPM), and is contingent upon execution of such assignment. This Revision adds 50 MW of intertie transmission demand at the John Day Substation Point of Receipt (POR) and at the California-Oregon Border Point of Delivery (POD). This assignment replaces the assignment executed on February 27, 2004 under Revision No. 7. These changes become effective on the Start Date, January 1, 2005.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2005.
Termination Date: at 0000 hours on January 1, 2006

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 1364703							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[2]	John Day Substation 500 kV	BPA[3]	50,000[4]	COB (500 kV)	BPA	50,000[4]	CISO (PPM)
Total Reserved Capacity			50,000			50,000	

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

---

[1] See HPP Contract No. 98TX-10154, Revision 11 to Exhibit A
[2] If the Delivering Party or Resource is not known at the time of Application, the Transmission customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[3] Bonneville Power Administration (BPA).
[4] This transmission demand is not entitled to Right of First Refusal

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
PTP-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VANALDERWERELT	By: /S/ NANCY E MORGAN
Name: **Peter C vanAlderwerelt** *(Print/Type)*	Name: **Nancy E. Morgan** *(Print/Type)*
Title: **Sr. Vice President**	Title: **Transmission Sales Manager**
Date: **11/30/04**	Date: **1/7/05**

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EXHIBIT A
TABLE 12
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Table No. 12 provides for 180 MW of Transmission Service from the John Day Point of Receipt to the California Oregon Border Point of delivery. Service to begin January 1, 2005, and end January 1, 2009. This Table 12 becomes effective on the date of execution.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on the January 1, 2005.
Termination Date: at 0000 hours on January 1, 2009

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER

The OASIS Assignment Reference Number (AREF) is: 1362012							
Delivering Party (Resource)	**POR Name & Voltage**	**POR Control Area**	**Reserved Capacity (kW)**	**POD Name & Voltage**	**POD Control Area**	**Reserved Capacity (kW)**	**Receiving Party**
PPM Energy or Various[1]	John Day Substation 500 kV	BPA[2]	180,000[3]	COB (500 kV)	BPA	180,000	CISO (PPM)
Total Reserved Capacity			180,000			180,000	

3. POINT(S) OF RECEIPT

(a) **John Day Substation Point of Receipt**

Location: the point in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: scheduled quantities.

[1] If the Delivering Party or Resource is not known at the time of Application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.
[2] Bonneville Power Administration (BPA).
[3] This transmission demand is entitled to Right of First Refusal.

4. **POINT(S) OF DELIVERY**

(a) **California - Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border (COB) where Bonneville shall make electric power available for the Transmission Customer;

Voltage: 500 kV;

Metering: scheduled quantities.

(b) **Description of Transfer Points of Delivery**
Not applicable.

5. **DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Not applicable.

6. **NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
Not applicable.

7. **SERVICE AGREEMENT CHARGES**

(a) **Transmission Charge**
PTP-04 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not applicable.

(2) **Short Distance Discount (SDD)**
Not applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
Not applicable.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**
Not Applicable.

PPM ENERGY, INC.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ PETER C VAN ALDERWERELT	By: /S/ NANCY E MORGAN
Name: **Peter C. van Alderwerelt** *(Print/Type)*	Name: Nancy E. Morgan *(Print/Type)*
Title: **Sr. Vice President**	Title: Acting Transmission Sales Manager
Date: **12/13/04**	Date: **11-24-04**

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MOA No. 96MS-95363
Final Draft Dated 3/21/97

AUTHENTICATED

MEMORANDUM OF AGREEMENT
providing for
POINT-TO-POINT TRANSMISSION SERVICE
between the
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE
and the
BONNEVILLE POWER ADMINISTRATION
POWER BUSINESS LINE

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Exhibit A	(Point-to-Point Transmission Service Terms and Conditions (Tariff))
Exhibit B	(Application for Point-to-Point Transmission Service)
Exhibit C	(Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit D	(System Impact Study Agreement)
Exhibit E	(Facilities Study Agreement)
Exhibit F	(Transmission Scheduling Provisions)
Exhibit G	(Reservation Confirmation Request for Short-Term Point-to-Point)
Exhibit H	(Wholesale Power and Transmission Rate Schedules)
Exhibit I	(Facilities Charges)

This MEMORANDUM OF AGREEMENT (MOA) is signed this 25th day of March, 1997, by and between the Bonneville Power Administration Transmission Business Line (hereinafter referred to as "Transmission Business Line") and the Bonneville Power Administration Power Business Line (hereinafter referred to as "Power Business Line"). The Bonneville Power Administration, as a whole, will be referred to as "BPA." The Transmission Business Line and the Power Business Line are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below. It is the intent of the Parties to implement the administrative separation and transmission comparability principles of the Federal Energy Regulatory Commission (Commission) through this MOA.

ARTICLE 1
SCOPE

1.1 **Terms and Conditions.** The terms and conditions under which the Point-to-Point (PTP) Transmission Service is provided are pursuant to this MOA and to the PTP Transmission Service Terms and Conditions (Tariff). The Tariff in effect at the time of signature of this MOA is hereby incorporated by this reference and made a part of this MOA as Exhibit A. The Transmission Business Line is "Bonneville" as that term is used in the Tariff. Because the Transmission Business Line and the Power Business Line are legally the same entity, the following provisions of the Tariff do not apply; provided, however, that such provisions of the Tariff shall apply to the extent rights hereunder are assigned pursuant to section 15.0 of the Tariff:

1.1.1 section 7.5 [parallel path provisions];

1.1.2 section 7.3 [reciprocity];

1.1.3 section 18.2 [stranded costs];

1.1.4 section 20.1(b), 20.1(c), 20.1 (f) and 20.1(g) [billing and payment];

1.1.5 sections 6.4 and 24 [dispute resolution];

1.1.6 section 21 [regulatory filings];

1.1.7 section 22 [liability and indemnification]; and

1.1.8 section 23 [creditworthiness].

Unless otherwise mutually agreed in writing by the Parties, the Transmission Business Line may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory or preferential. The Parties agree that transmission service provided pursuant to this MOA may be provided under a Commission-approved successor tariff after September 30, 2001, if the Transmission Business Line implements a tariff that supersedes the Tariff.

1.2 **Application.** The Application for Firm Point-to-Point (PTP) Transmission Service requested by the Power Business Line and accepted by the Transmission Business Line for this MOA is hereby incorporated by this reference and made a part of this MOA as Exhibit B.

1.3 **Statement of Specifications for Long-Term Firm Transmission Service.** The Statement of Specifications (including Ancillary Services) for Long-Term Firm Point-to-Point Transmission Service under this MOA requested by the Power Business Line and accepted by the Transmission Business Line are hereby incorporated by this reference and made a part of this MOA as Exhibit C.

1.4 **System Impact/Facilities Study.** Study Agreements for a System Impact Study and/or a Facilities Study, if performed pursuant to this MOA, are hereby incorporated by this reference and made a part of this MOA as Exhibits D and E, respectively.

1.5 **Transmission Scheduling Provisions.** The Transmission Scheduling Provisions are hereby incorporated by this reference and made a part of this MOA as Exhibit F. All transactions under this MOA shall be scheduled in accordance with the Transmission Scheduling Provisions in Section 2.7(d) of the Tariff and Exhibit F of this MOA.

1.6 **Reservation Confirmation Request for Short Term PTP.** The Reservation Confirmation Request for Short Term PTP is hereby incorporated by this reference and made part of this MOA as Exhibit G. The service specifications for Short-Term Firm and Nonfirm transmission service under this MOA shall be as provided in Exhibit G.

1.7 **BPA Wholesale Power and Transmission Rate Schedules.** The BPA Wholesale Power and Transmission Rate Schedules are hereby incorporated by this reference and made part of this MOA as Exhibit H.

1.8 **Facilities Charges.** All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this MOA are hereby incorporated by this reference and made a part of this MOA as Exhibit I.

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the Tariff.

ARTICLE 3
TERM

Service under this MOA shall commence on 2400 hours on September 30, 1996, and terminate on 2400 hours on March 31, 2017. This MOA may be terminated prior to March 31, 2017 as provided in the Tariff. Specific terms of service for individual long-term firm transactions under this MOA are provided in Exhibit C.

ARTICLE 4
CHARGES AND PAYMENTS

The Power Business Line shall transfer to the Transmission Business Line sufficient funds to cover the following charges as applicable, pursuant to Commission pricing policy, for transmission service provided hereunder.

4.1 Charges for Transmission Service. The Power Business Line shall pay the Transmission Business Line for charges as applicable for services provided hereunder pursuant to the rate schedules in Exhibit H.

4.1.1 All applicable charges pursuant to the Point-to-Point Transmission Rate (PTP-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules), as specified in Exhibit C and Exhibit G;

4.1.2 All applicable charges pursuant to the Ancillary Products and Services Rate (APS-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit C and Exhibit G;

4.1.3 Reserved Nonfirm Transmission Rate (RNF-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit G;

4.1.4 Energy Transmission Rate (ET-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit G;

4.1.5 Advance Funding Rate (AF-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) for facilities listed in Exhibit I;

4.1.6 Use-of-Facilities Rate (UFT-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) for facilities listed in Exhibit I;

4.1.7 Southern Intertie Rate (IS-96, or its successor, as revised and listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit C and Exhibit G;

4.1.8 Montana Intertie Rate (IM-96, or its successor, as revised as listed in the Wholesale Power and Transmission Rate Schedules) as specified in Exhibit G.

4.2 Billing and Payment. Bills for all services provided under this MOA shall be rendered monthly by the Transmission Business Line and all such bills shall be due and payable in accordance with section 20 of the Tariff and Article 1.1.4 of this MOA, as appropriate, or as otherwise agreed by the Parties.

ARTICLE 5
NOTICES

5.1 Notices Relating to Provisions of this MOA. Any notice, request, demand, or statement which may be given to or be made upon either Party by the other Party under any of the provisions of this MOA, except those specified in paragraph 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If the notice is to the Power Business Line:

Bonneville Power Administration, Power Business Line
Contact: Manager, Transmission Services - PST
905 NE 11th Avenue
P.O. Box 3621
Portland, OR 97208-3621

If the notice is to the Transmission Business Line:

Bonneville Power Administration, Transmission Business Line
Contact: Account Executive for the Power Business Line - TM
905 NE 11th Avenue
P.O. Box 3621
Portland, OR 97208-3621

5.2 **Notices of an Operating Nature.** Any notice, request, or demand pertaining to matters of an operating nature, including notices required pursuant to Article 8.4 but exclusive of requests for additional or modified transmission service under this MOA, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should the same not be in writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. Point(s) of contact pursuant to this section shall be communicated by the Parties under separate letter within 45 days from the date this MOA is signed.

ARTICLE 6
SYSTEM OPERATIONS

The Power Business Line, having Points of Interconnection with Federal Columbia River Transmission System (FCRTS), shall be required to designate a Control Area and to comply with the System Operation and Interconnection Requirements in section 7.4 of the Tariff prior to commencement of PTP Transmission Service hereunder. Points of Delivery in Exhibits C and G shall be governed by agreements between the Transmission Business Line and parties interconnected with the FCRTS.

ARTICLE 7
SPECIFICATIONS FOR ANCILLARY SERVICES

Ancillary Services provided by the Transmission Business Line to the Power Business Line pursuant to this MOA shall be provided in accordance with section 8 of the Tariff, and shall

be billed in accordance with section 20 of the Tariff and Articles 1.1.4 and 4.2 of this MOA. The Ancillary Services provided to the Power Business Line shall be specified in the Statement of Specifications, Exhibit C and in Exhibit G of this MOA. The Power Business Line shall pay the Transmission Business Line for such Ancillary Services.

ARTICLE 8
MISCELLANEOUS

8.1 **Interconnection with Other Systems.** Nothing contained in this MOA shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this MOA or amending or entering into such agreements.

8.2 **Governing Law.** This MOA shall be interpreted, construed, and enforced in accordance with Federal law.

8.3 **Amendments.** Except as provided in Article 1.1 and Article 8.4, and unless otherwise mutually agreed in writing by the Parties, the Transmission Business Line may change this MOA upon, and only upon, a determination by the Commission that such change is just, reasonable and not unduly discriminatory or preferential. Otherwise, this MOA may be amended upon mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

8.4 **Revision of Exhibits.** If the Transmission Business Line determines that any changes to Exhibits C, D, E, F, G, H, or I are necessary to reflect changes specified below, such new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein.

8.4.1 If the Parties mutually agree to change Exhibit C pursuant to this MOA, the Transmission Business Line shall prepare and issue a revised Exhibit C, or Table thereto, as appropriate. The Transmission Business Line reserves the

right to amend contiguous Point of Delivery provisions in section 3 of the Index and General Specifications of Exhibit C.

8.4.2 If the Parties mutually agree to perform a System Impact Study and/or Facilities Study, the Transmission Business Line shall prepare a revised Exhibit D and/or Exhibit E, as applicable, incorporating the System Impact Study and/or Facilities Study, the associated Study Agreement(s), and any supporting or clarifying documents as agreed.

8.4.3 For changes to any of the provisions contained in the Transmission Scheduling Provisions Exhibit (Exhibit F) to reflect updated transmission scheduling practices, the Transmission Business Line shall prepare a new Exhibit F to be incorporated into this MOA.

8.4.4 For changes to the Reservation Confirmation for Short-Term PTP (Exhibit G) to reflect updated reservation confirmation practices, the Transmission Business Line shall prepare a new Exhibit G to be incorporated into this MOA.

8.4.5 The Transmission Business Line may change rates pursuant to applicable law and procedures. The Transmission Business Line shall prepare a new Exhibit H reflecting such changes, and such new Exhibit H shall be incorporated into this MOA.

8.4.6 The Transmission Business Line reserves the right to revise Exhibit I annually to reflect changes in: (a) the yearly noncoincidental demands on the facility under this MOA and other agreements; (b) changes in Investment and Amortization (I&A) annual cost ratio; and (c) changes in Operation and Maintenance (O&M) annual cost. The Transmission Business Line shall prepare a new Exhibit I reflecting such changes, and such new Exhibit I shall be incorporated into this MOA.

8.5 **Conversion to Future Tariffs.** Upon mutual agreement of the Parties, the notice periods for terminating this MOA and for commencing service under another tariff offered by the Transmission Business Line may be shortened.

8.6 **Temporary Load Shifts and Maintenance Notification.** The Parties may temporarily interrupt or reduce deliveries of electric power if either party determines that such interruption or reduction is necessary or desirable in case of system emergencies, operational constraints, Uncontrollable Forces, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on facilities used to make deliveries under this MOA. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of such interruption or outage.

Load shift and outage reports must be submitted to the Transmission Business Line within four (4) days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. The point of contact will be designated pursuant to Article 5.2 of this MOA. On receipt of the Power Business Line's data, the Transmission Business Line will take the appropriate steps to normalize the billing determinants at the affected point(s) of delivery. If Power Business Line reports are not received in a timely manner, the Transmission Business Line shall assess charges based on available data.

8.7 **Severability.** In the event any terms, covenants, or conditions of this MOA, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this MOA or any amendment hereto, and their application shall remain in full force and effect.

8.8 **Computation of Time.** On computing any period of time prescribed or allowed by this MOA, the day of the act, event, or default from which the designated period of

time begins to run shall not be included. The last day of this period so computed shall be included unless it is a Saturday, Sunday, or Federal holiday, in which event the period shall run until the end of the next business day which is neither a Saturday, Sunday, or Federal holiday. For purposes of the administration of this MOA, Pacific Time shall be used.

8.9 **No Third Party Beneficiaries.** This MOA creates rights and obligations only between the Parties hereto. The Parties hereto expressly do not intend to create any obligation or promise of performance to any other third person or entity nor have the Parties conferred any right or remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns to enforce this MOA.

8.10 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this MOA, or with respect to any other matter arising in connection with this MOA, shall not be deemed a waiver with respect to any other or subsequent default or matter.

8.11 **Successors and Assigns.** This MOA shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

8.12 **MOA Governs.** In the event of any irreconcilable difference between the Tariff and this MOA, the language of this MOA shall govern.

8.13 **Dispute Resolution.** All disputes between the Parties pursuant to this MOA shall be resolved by BPA's Chief Operating Officer.

8.14 **Entire Agreement.** This MOA constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect thereof.

IN WITNESS WHEREOF, the duly authorized representatives of the Transmission Business Line and the Power Business Line have signed this MOA as of the date first above written.

Bonneville Power Administration
Transmission Business Line

By /S/ ALLAN F. PASCHKE

Name Allan F. Paschke

Title Transmission Account Executive

Date 3/25/97

Bonneville Power Administration
Power Business Line

By /S/ TRACEY L. SALAZAR

Name Tracey L. Salazar
(Print/Type)

Title Manager Transmission Services
(Print/Type)

Date 3/25/97

(W:\TMC\CT\PBLPTP.DOC)

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery at the California-Oregon Border (COB)

1. TERM OF TRANSACTION

Start Date: 2400 hours, March 31, 1997.
Termination Date: 2400 hours, March 31, 2017.

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various receiving parties.

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Pacific Gas & Electric

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation, 500 kV	COB, 500 kV	4/1/97-4/30/97: 571 MW	IS-96
		5/1/97-5/31/97: 431 MW	IS-96
		6/1/97-6/30/97: 531 MW	IS-96
		7/1/97-7/31/97: 631 MW	IS-96
		8/1/97-8/31/97: 631 MW	IS-96
		9/1/97-3/31/17: 700 MW	IS-96

6. DESCRIPTION OF POINTS OF INTERCONNECTION

JOHN DAY SUBSTATION

Location: the point in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

7. DESCRIPTION OF POINTS OF DELIVERY

CALIFORNIA/OREGON (COB) POINT OF DELIVERY

Location: the points in the Malin and Captain Jack Substations where the 500 kV facilities of PacifiCorp and the Government are connected;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

8. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable per section 1.1.2 of this MOA.

9. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

10. SHORT DISTANCE DISCOUNT

Not Applicable.

11. ANCILLARY SERVICES

a. Load Regulation

Load Regulation is provided by Pacific Gas & Electric.

b. Energy Imbalance

Deliveries are made to another control area.

Energy Imbalance is not required for this transaction.

c. Control Area Reserves for Resources

Control Area Reserves for Resources are provided pursuant to section 6(a) of the Index and General Specifications of this Exhibit C.

Control Area Reserves for Resources are not required for this transaction.

d. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are not required for this transaction.

e. Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Customer:
Modesto, Santa Clara, Redding (MSR)

1. TERM OF TRANSACTION

Start Date: 2400 hours, December 31, 1997
Termination Date: 2400 hours, April 15, 2013

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various Receiving Parties

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Pacific Gas & Electric

5. SUMMARY OF POINTS OF INTERTIE INTERCONNECTIONS AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day	COB, (500 kV)	01/01/98 - 04/15/2013: 150 MW	IS-96

6. DESCRIPTION OF POINTS OF INTERCONNECTION

John Day Substation

Location: the point in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: Quantities are to be scheduled.

7. DESCRIPTION OF INTERTIE POINTS OF DELIVERY

California/Oregon (Cob) Point Of Delivery

Location: the points in the Malin and Captain Jack Substations, where the 500 kV facilities of PacifiCorp and the Government are connected;

Voltage: 500 kV;

Metering: Quantities are to be scheduled.

8. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable per section 1.1.2 of this MOA

9. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None

10. SHORT DISTANCE DISCOUNT

Not applicable

11. ANCILLARY SERVICES

a. Load Regulation
Load Regulation is provided by Pacific Gas & Electric.

b. Energy Imbalance
Deliveries are made to another control area. Energy Imbalance is not required for this transaction.

c. Control Area Reserves for Resources
Control Area Reserves for Resources are provided pursuant to section 6(a) of the Index and General Specifications of this Exhibit C. Control Area Reserves for Resources are not required for this transaction.

d. Control Area Reserves for Interruptible Purchases
Control Area Reserves for Interruptible Purchases are not required for this transaction.

e. Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

BONNEVILLE POWER ADMINISTRATION
Transmission Business Line

By: _____

Name: Allan F. Paschke

Title: Transmission Account Executive

Date: 12/11/97

ACCEPTED:
BONNEVILLE POWER ADMINISTRATION
Power Business Line

By: _____

Name: Tracey L. Salazar

Title: Manager, Transmission Services

Date: 12-12-97

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AUTHENTICATED

MOA No. 96MS-95363
Power Business Line Customer
Bay Area Rapid Transit
Effective at 0000 hours
on August 1, 2002

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Customer: Bay Area Rapid Transit (BART)

This Table 60 reflects a conversion of the Intertie segment of long-term firm transmission service associated with Power Sales Contract No. 96MS-95177 from the Statement of Principles, Memorandum of Agreement No. 96MS-96060, to this PTP Agreement.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on August 1, 2002.
Termination Date: at 0000 hours on July 1, 2016.

2. SUMMARY OF POINT OF INTERCONNECTION AND POINT OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY

2.1 Oasis Assignment Reference Number: 483765

Effective Dates	Delivering Party (Resource)	POI	POI Control Area	Maximum POI Demand (MW)[1]	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
8/1/2002 - 6/30/2003	PBL Contract with BART (Contract No. 96MS-95177)	John Day Substation, 500 kV	TBL	14 MW	California-Oregon Border	PG&E	14 MW	Various Receiving Parties
7/1/2003 - 6/30/2016	PBL Contract with BART (Contract No. 96MS-95177)	John Day Substation, 500 kV	TBL	50 MW	California-Oregon Border	PG&E	50 MW	Various Receiving Parties

Maximum Reserved Capacity 50 MW

3. DESCRIPTION OF POINT OF INTERCONNECTION

John Day Substation

Location: the point in the Government's John Day Substation where the line terminals of the Southern Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

1 Conversion does not include Right of First Refusal (ROFR/Rollover).

4. DESCRIPTION OF POINT OF DELIVERY

California-Oregon Border (COB)

Location: the points in the Malin and Captain Jack Substations where the 500 kV facilities of PacifiCorp and the Government are connected;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED:
50 MW.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION:
Not applicable per section 1.12 of this MOA.

7. NAME (S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE:
Not applicable.

8. SERVICE UNDER THIS AGREEMENT WILL BE SUBJECT TO SOME COMBINATION OF THE CHARGES DETAILED BELOW. (THE APPROPRIATE CHARGES FOR TRANSACTIONS WILL BE DETERMINED IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE TARIFF).

8.1 Transmission Charge:
IS-02 Rate Schedule or Successor Rate Schedule.

8.1.1 Reservation Fee:
Not applicable.

8.1.2 Short Distance Discount:
Not applicable.

8.2 System Impact and/or Facilities Study Charge(s):
Facilities Charges are not required at this time for the service under this Table 60.

8.3 Direct Assignment and Use-of-Facilities Charges:
Facilities Charges are not required at this time for the service under this Table 60.

8.4 Ancillary Service Charges:
ACS-02 Rate Schedule or Successor Rate Schedule.

8.4.1 Ancillary Services are provided as follows:

		Provided By	Contract No.
8.4.1.1	**Scheduling, System Control And Dispatch**	Transmission Provider	96MS-95363
8.4.1.2	**Reactive Supply And Voltage Control**	Transmission Provider	96MS-95363
8.4.1.3	**Regulation & Frequency Response**	Transmission Provider	96MS-95363
		As Applicable	
8.4.1.4	**Energy Imbalance Service**	Transmission Provider	96MS-95363
		As Applicable	
8.4.1.5	**Operating Reserve – Spinning Reserve**	Transmission Provider	96MS-95363
		As Applicable	
8.4.1.6	**Operating Reserve – Supplemental Reserve**	Transmission Provider	96MS-95363
		As Applicable	

8.4.2 Notification of changes in Ancillary Services Provider:
Except for those Ancillary Services that must be provided by the Transmission Provider, the Transmission Customer may make an annual election to obtain some or all Ancillary Services from a third party or to self-supply Ancillary Services.

If the Transmission Customer intends that an entity other than the Transmission Provider provide any Ancillary Service for any Fiscal year (October 1 through September 30), then the Transmission Customer must notify the Transmission Provider of its election of an Ancillary Service provider by July 1 of each Fiscal Year. Such election will be effective October 1 of the next Fiscal Year. If the Transmission Customer does make such election, the Transmission Provider will notify the Transmission Customer no later than September 1 of the Fiscal Year prior to the Fiscal Year for which such election is made, whether the Transmission Customer's alternative arrangements are comparable to purchasing the Ancillary Services(s) from the Transmission Provider, and are consistent with the Transmission Provider's business practices for self-supply or third party supply.

In the event that, as to any Ancillary Service, the Transmission Customer's alternative arrangements are *not* comparable, or are inconsistent with the Transmission Provider's business practices for self-supply or third party supply, the Ancillary Service provider for such Ancillary Service for the next Fiscal Year shall be the Transmission Provider.

9. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom the sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

TRANSMISSION BUSINESS LINE

By: /S/ ALLAN F PASCHKE

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: 8/6/02

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

POWER BUSINESS LINE

By: /S/ ANNE E DRAPER

Name: Anne E. Draper
Print/Type

Title: Manager, Transmission & Reserve Services

Date: 8 August 02

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery to the Nevada-Oregon Border (NOB)

1. TERM OF TRANSACTION

Start Date: at 2400 hours on June 30, 2000
Termination Date: 2400 hours on June 30, 2010

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
PBL – Various Resources	Big Eddy Substation	TBL	24 MW	NOB	LADWP	24 MW	Various receiving parties
Total Transmission Demand			24 MW			24 MW	

3. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

4. DESCRIPTION OF POINTS OF DELIVERY

Nevada-Oregon Border

Location: the point where the Government's 1,000 kV DC line crosses the

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[1] If the Delivering Party or Resource is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party and Resource at the time of preschedule.

Nevada/Oregon border;

Voltage: 1,000 kV;

Metering: quantities to be scheduled.

5. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLICATION**
Not applicable per section 1.12 of this MOA

6. **NAMES(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None

7. **SHORT DISTANCE DISCOUNT**
Not applicable

8. **ANCILLARY SERVICES PROVIDED**

(a) **Load Regulation**
Load Regulation is not required for this transaction.

(b) **Energy Imbalance**
Energy Imbalance is not required for this transaction.

(c) **Control Area Reserves for Resources Control Area Reserves for Resources are not required for this transaction.**
Control Area Reserves for Resources are not required for this transaction.

(d) **Control Area Reserves for Interruptible Purchases**
Control Area Reserves for Interruptible Purchases are not required for this transaction.

(e) **Transmission Losses**
Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

9. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom the sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

TRANSMISSION BUSINESS LINE

By: Allan F. Paschke

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: 6/14/00

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

POWER BUSINESS LINE

By: Anne E. Draper

Name: Anne E. Draper
Print/Type

Title: Manager,
Transmission Acquisition and Reserves

Date: 6/16/00

10-16-00A10:43 RCVD

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery at the Nevada-Oregon Border (NOB)

1. TERM OF TRANSACTION

Start Date: 2400 hours, June 1, 2003, subject to the payment of the reservation fee as noted below.
Termination Date: 2400 hours, May 31, 2005

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various receiving parties

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Los Angeles Department of Water & Power (LADWP)

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation	NOB, 500 kV	6/1/03 - 5/31/05: 150 MW	IS-96

Reservation Fee: The annual non-refundable reservation fee schedule shall be applied as follows: (1) $191,000 due and payable to TBL within 30 days of execution of this Table 51; (2) another $191,000 due and payable within 1 year and 30 days of the execution date of this Table 51; and (3) another $191,000 due and payable within 2 years and 30 days of execution of this table 51. TBL shall bill PBL within 30 days before the annual execution.

Scheduling: Firm transmission for 150 MW effective on the Effective Date as stated in Section 1 above.

6. DESCRIPTION OF POINTS OF INTERCONNECTION

BIG EDDY SUBSTATION

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

7. DESCRIPTION OF POINTS OF DELIVERY

NEVADA/OREGON BORDER (NOB) POINT OF DELIVERY

Location: the point where the Government's 500 kV DC line crosses the Nevada/Oregon border;

Voltage: 500 kV;

Metering: quantities to be scheduled.

8. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Not applicable per section 1.1.2 of this MOA

9. NAME (S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None

10. SHORT DISTANCE DISCOUNT

Not Applicable

11. ANCILLARY SERVICES

(a) Load Regulation

Load Regulation is provided by LADWP. Load Regulation is not required from the TBL for this transaction.

(b) Energy Imbalance

Provided under this Table 51.

(c) Control Area Reserves for Resources

Provided under this Table 51.

(d) Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are not required for this transaction.

(e) Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

BONNEVILLE POWER ADMINISTRATION
Transmission Business Line

By: _____

Name: Allan F. Paschke

Title: Transmission Account Executive

Date: 9/14/00

BONNEVILLE POWER ADMINISTRATION
Power Business Line

By: _____

Name: Anne E. Draper
(Print/Type)

Title: Acquisition and Reserve Services

Date: 10/13/00

(w:/mcp/tmc/ct/pbl/95363/ct23.doc)

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery at the Nevada-Oregon Border (NOB)

1. TERM OF TRANSACTION

Start Date: 2400 hours, March 31, 1997.
Termination Date: 2400 hours, March 31, 2017.

2. DELIVERING PARTY/RESOURCE

Bonneville Power Administration Power Business Line, various contracts for delivery of power from the FCRPS.

3. RECEIVING PARTY

Various receiving parties.

4. CONTROL AREA

Control Area of Origin: BPA
Control Area of Delivery: Los Angeles Department of Water & Power (LADWP)

5. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation, 500 kV	NOB, 500 kV	4/1/97-3/31/17: 300 MW	IS-96
		Total 300 MW	

6. DESCRIPTION OF POINTS OF INTERCONNECTION

BIG EDDY SUBSTATION

Location: the point in the Government's Big Eddy Substation where the line terminals of the Government's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

7. **DESCRIPTION OF POINTS OF DELIVERY**

NEVADA/OREGON BORDER (NOB) POINT OF DELIVERY

Location: the point where the Government's 500 kV DC line crosses the Nevada/Oregon border;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

8. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**

Not applicable per section 1.1.2 of this MOA.

9. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**

None.

10. **SHORT DISTANCE DISCOUNT**

Not Applicable.

11. **ANCILLARY SERVICES**

a. **Load Regulation**

Load Regulation is provided by LADWP.
Load Regulation is not required for this transaction.

b. **Energy Imbalance**

Energy Imbalance is provided pursuant to section 6(a) of the Index and General Specifications to this Exhibit C.

Energy Imbalance is not required for this transaction.

c. Control Area Reserves for Resources

Control Area Reserves for Resources are provided pursuant to section 6(a) of the Index and General Specifications to this Exhibit C.

Control Area Reserves for Resources are not required for this transaction.

d. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are not required for this transaction.

e. Transmission Losses

Transmission Losses shall be provided pursuant to section 6(c)(6) of the Index and General Specifications to this Exhibit C.

AUTHENTICATED

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery to the Big Eddy Substation.

This revision reflects an election to exercise Right of First Refusal.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on October 1, 2004.
Termination Date: 0000 hours on October 1, 2005.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

2.1 OASIS Assignment Reference Number: 1321893

Delivering Party (Resource)	POI	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
Various Delivering Parties (Special Intertie Service)	Nevada-Oregon Border (NOB) 1000 kV	LADWP	100 MW	Big Eddy Substation 500 kV	TBL	100 MW	Various Receiving Parties (Special Intertie Service)
Total Transmission Demand			100 MW			100 MW	

3. DESCRIPTION OF POINT OF INTERCONNECTION

NEVADA - OREGON BORDER (NOB)

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where the Transmission Provider shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

4. DESCRIPTION OF POINT OF DELIVERY

BIG EDDY SUBSTATION

Location: The point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

5. MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED
100 MW.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION
Not applicable per section 1.12 of this MOA.

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE
None.

8. SERVICE UNDER THIS AGREEMENT WILL BE SUBJECT TO SOME COMBINATION OF THE CHARGES DETAILED BELOW. (THE APPROPRIATE CHARGES FOR TRANSACTIONS WILL BE DETERMINED IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE TARIFF.)

8.1 **Transmission Charge:**
PTP-04 Rate Schedule or Successor Rate Schedule.

8.1.1 **Reservation Fee:**
Not applicable.

8.1.2 **Short Distance Discount (SDD):**
Not applicable.

8.2 **System Impact and/or Facilities Study Charge(s):**
System Impact and/or Facilities Study Charges are not required for service under this Table 53.

8.3 **Direct Assignment and Use-of-Facilities Charges:**
Facilities Charges are not required at this time for the service under this Table 53.

8.4 **Ancillary Service Charges:**
ACS-04 Rate Schedule.

8.4.1 **Ancillary Services are provided as follows:**

	Ancillary Service	Provided By	Contract No.
8.4.1.1	Scheduling, System Control, and Dispatch	BPA (TBL)	96MS-95363
8.4.1.2	Reactive Supply and Voltage Control from Generation Sources	BPA (TBL)	96MS-95363
8.4.1.3	Regulation and Frequency Response	- -	- -
8.4.1.4	Energy Imbalance	- -	- -
8.4.1.5	Operating Reserve – Spinning Reserve	BPA (TBL) As Applicable	96MS-95363
8.4.1.6	Operating Reserve – Supplemental Reserve	BPA (TBL) As Applicable	96MS-95363

8.4.2 **Notification of Changes in Ancillary Services Provider:** Except for those Ancillary Services that must be provided by the Transmission Provider, the Transmission Customer may make an annual election to obtain some or all Ancillary Services from a third party or to self-supply Ancillary Services.

If the Transmission Customer intends that an entity other than the Transmission Provider provide any Ancillary Service for any Fiscal Year (October 1 through September 30), then the Transmission Customer must notify the Transmission Provider of its election of an Ancillary Service provider by July 1 of each Fiscal Year. Such election will be effective October 1 of the next Fiscal Year. If the Transmission Customer *does* make such election, the Transmission Provider will notify the Transmission Customer no later than September 1 of the Fiscal Year prior to the Fiscal Year for which such election is made, whether the Transmission Customer's alternative arrangements are comparable to purchasing the Ancillary Service(s) from the Transmission Provider, and are consistent with the Transmission Provider's business practices for self-supply or third party supply. In the event that, as to any Ancillary Service, the Transmission Customer's alternative arrangements are *not* comparable, or are inconsistent with the Transmission Provider's business practices for self-supply or third party supply, the Ancillary Service provider for such Ancillary Service for the next Fiscal Year shall be the Transmission Provider.

If the Transmission Customer does *not* elect to obtain any Ancillary Services from a third party or to self-supply any Ancillary Services, the Ancillary Service provider for the next Fiscal Year shall be the Transmission Provider.

9. OTHER PROVISIONS

In accordance with section 2.2 of the Open Access Transmission Tariff, the Transmission Customer has a reservation priority for the long-term firm transmission service provided under this Table 53. The Transmission Customer has elected to exercise such priority right with the Transmission Provider, by execution of this Table 53, to continue to take transmission service after September 30, 2004. If, due to the Celilo (DC Southern Intertie) Modernization Project, transmission is not available during some periods during the term of this revised Table, the Transmission Customer will, nevertheless, pay to the Transmission Provider each month the full long-term firm PTP transmission service charge based upon a demand of 100 MW, plus ancillary service and any other appropriate charges.

This obligation shall apply even if no transmission was available to the Transmission Customer for such month. This paragraph is not intended to affect the Transmission Customer's obligation to pay the full transmission service charge and other charges in the event transmission is unavailable for reasons other than the Celilo (DC Southern Intertie) Modernization Project.

10. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
TRANSMISSION BUSINESS LINE

By: **/S/ ALLAN F. PASCHKE**

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: **7/26/04**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
POWER BUSINESS LINE

By: **/S/ ANNE E. DRAPER**

Name: Anne E. Draper
Print/Type

Title: Manager,
Transmission Acquisition and Reserves

Date: **7/29/04**

AUTHENTICATED

STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

Power Business Line Delivery to the Big Eddy Substation.

This revision reflects an election to exercise Right of First Refusal.

1. **TERM OF TRANSACTION**
Start Date: at 0000 hours on October 1, 2004.
Termination Date: 0000 hours on October 1, 2005.

2. **SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT**

2.1 OASIS Assignment Reference Number: 1321898

Delivering Party (Resource)	POI	POI Control Area	Maximum POI Demand (kW)	POD (Voltage)	POD Control Area	Maximum POD Demand (kW)	Receiving Party
Various Delivering Parties (Special Intertie Service)	Nevada-Oregon Border (NOB) 1000 kV	LADWP	100 MW	Big Eddy Substation 500 kV	TBL	100 MW	Various Receiving Parties (Special Intertie Service)
Total Transmission Demand			100 MW			100 MW	

3. **DESCRIPTION OF POINT OF INTERCONNECTION**

NEVADA - OREGON BORDER (NOB)

Location: The point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border (NOB), where the Transmission Provider shall receive Electric Power for transmission hereunder;

Voltage: 1000 kV;

Metering: quantities to be scheduled.

4. DESCRIPTION OF POINT OF DELIVERY

BIG EDDY SUBSTATION

Location: The point in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities to be scheduled.

5. MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED
100 MW.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION
Not applicable per section 1.12 of this MOA.

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE
None.

8. SERVICE UNDER THIS AGREEMENT WILL BE SUBJECT TO SOME COMBINATION OF THE CHARGES DETAILED BELOW. (THE APPROPRIATE CHARGES FOR TRANSACTIONS WILL BE DETERMINED IN ACCORDANCE WITH THE TERMS AND CONDITIONS OF THE TARIFF.)

8.1 **Transmission Charge:**
PTP-04 Rate Schedule or Successor Rate Schedule.

8.1.1 **Reservation Fee:**
Not applicable.

8.1.2 **Short Distance Discount (SDD):**
Not applicable.

8.2 **System Impact and/or Facilities Study Charge(s):**
System Impact and/or Facilities Study Charges are not required for service under this Table 54.

8.3 **Direct Assignment and Use-of-Facilities Charges:**
Facilities Charges are not required at this time for the service under this Table 54.

8.4 **Ancillary Service Charges:**
ACS-04 Rate Schedule.

8.4.1 **Ancillary Services are provided as follows:**

	Ancillary Service	Provided By	Contract No.
8.4.1.1	Scheduling, System Control, and Dispatch	BPA (TBL)	96MS-95363
8.4.1.2	Reactive Supply and Voltage Control from Generation Sources	BPA (TBL)	96MS-95363
8.4.1.3	Regulation and Frequency Response	- -	- -
8.4.1.4	Energy Imbalance	- -	- -
8.4.1.5	Operating Reserve – Spinning Reserve	BPA (TBL) As Applicable	96MS-95363
8.4.1.6	Operating Reserve – Supplemental Reserve	BPA (TBL) As Applicable	96MS-95363

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If the Transmission Customer intends that an entity other than the Transmission Provider provide any Ancillary Service for any Fiscal Year (October 1 through September 30), then the Transmission Customer must notify the Transmission Provider of its election of an Ancillary Service provider by July 1 of each Fiscal Year. Such election will be effective October 1 of the next Fiscal Year. If the Transmission Customer *does* make such election, the Transmission Provider will notify the Transmission Customer no later than September 1 of the Fiscal Year prior to the Fiscal Year for which such election is made, whether the Transmission Customer's alternative arrangements are comparable to purchasing the Ancillary Service(s) from the Transmission Provider, and are consistent with the Transmission Provider's business practices for self-supply or third party supply. In the event that, as to any Ancillary Service, the Transmission Customer's alternative arrangements are *not* comparable, or are inconsistent with the Transmission Provider's business practices for self-supply or third party supply, the Ancillary Service provider for such Ancillary Service for the next Fiscal Year shall be the Transmission Provider.

If the Transmission Customer does *not* elect to obtain any Ancillary Services from a third party or to self-supply any Ancillary Services, the Ancillary Service provider for the next Fiscal Year shall be the Transmission Provider.

9. OTHER PROVISIONS

In accordance with section 2.2 of the Open Access Transmission Tariff, the Transmission Customer has a reservation priority for the long-term firm transmission service provided under this Table 54. The Transmission Customer has elected to exercise such priority right with the Transmission Provider, by execution of this Table 54, to continue to take transmission service after September 30, 2004. If, due to the Celilo (DC Southern Intertie) Modernization Project, transmission is not available during some periods during the term of this revised Table, the Transmission Customer will, nevertheless, pay to the Transmission Provider each month the full long-term firm PTP transmission service charge based upon a demand of 100 MW, plus ancillary service and any other appropriate charges.

This obligation shall apply even if no transmission was available to the Transmission Customer for such month. This paragraph is not intended to affect the Transmission Customer's obligation to pay the full transmission service charge and other charges in the event transmission is unavailable for reasons other than the Celilo (DC Southern Intertie) Modernization Project.

10. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for whom they sign.

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
TRANSMISSION BUSINESS LINE

By: **/S/ ALLAN F. PASCHKE**

Name: Allan F. Paschke
Print/Type

Title: Transmission Account Executive

Date: **7/26/04**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration
POWER BUSINESS LINE

By: **/S/ ANNE E. DRAPER**

Name: Anne E. Draper
Print/Type

Title: Manager,
Transmission Acquisition and Reserves

Date: **7/29/04**

AUTHENTICATED

Service Agreement No. 99TX-10251

SERVICE AGREEMENT
for
POINT-TO-POINT TRANSMISSION
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
BRITISH COLUMBIA POWER EXCHANGE CORPORATION

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Exhibit A (Statement of Specifications for Long-Term Firm Transmission Service)
Exhibit B (Facilities Charges)
Exhibit C (Ancillary Services)

This TRANSMISSION SERVICE AGREEMENT is made and entered into this 31sr day of May, 1999, by and between the Bonneville Power Administration (hereinafter referred to as "BPA") and British Columbia Power Exchange Corporation (hereinafter referred to as "the Transmission Customer"). The Transmission Customer and BPA are sometimes referred to individually as "Party" and collectively as "Parties," as the context suggests below.

ARTICLE 1
SCOPE OF SERVICE AGREEMENT

1.1 TERMS AND CONDITIONS

BPA agrees to provide and the Transmission Customer agrees to take and pay for PTP Transmission Services in accordance with the provisions of this Service Agreement and the Open Access Transmission Tariff (Tariff). The Tariff in effect at the time of execution of this Service Agreement is hereby incorporated by this

reference. BPA may change the terms and conditions of the Tariff upon, and only upon, a determination by the Commission that such change is just and reasonable and not unduly discriminatory or preferential.

1.2 STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

The Statement of Specifications for Long-Term Firm PTP Transmission Service under this Service Agreement requested by the Transmission Customer for each individual transaction and accepted by BPA is hereby incorporated and made a part of this Service Agreement as Exhibit A and made applicable to that transaction.

1.3 WHOLESALE POWER AND TRANSMISSION RATES SCHEDULES

BPA's Wholesale Power and Transmission Rates Schedules are hereby incorporated by this reference.

1.4 FACILITIES CHARGES

All applicable charges pursuant to the Direct Assignment Facilities Provisions for existing facilities and facilities built as a result of this Service Agreement are hereby incorporated as Exhibit B.

1.5 ANCILLARY SERVICES

The Ancillary Services for PTP Transmission Service under this Service Agreement are hereby incorporated as Exhibit C.

1.6 TRANSMISSION SCHEDULING PROVISIONS

The Transmission Customer shall schedule transmission transactions in accordance with BPA's Transmission Scheduling Provisions and Procedures as posted on BPA's OASIS located at the following Internet URL address:

http://www.nwoasis.org/OASIS/BPAT

ARTICLE 2
DEFINITIONS

Unless otherwise defined herein, all capitalized terms shall have the meanings set forth in the Tariff.

ARTICLE 3
TERM OF SERVICE AGREEMENT

Service under this Service Agreement shall commence at 2400 hours on June 12, 1999. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on June 12, 2004, or (b) 2400 hours on the date of termination established pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied.

ARTICLE 4
CHARGES AND PAYMENTS

4.1 CHARGES FOR TRANSMISSION SERVICE

The Transmission Customer shall pay BPA the applicable charges for services provided hereunder pursuant to the BPA Wholesale Power and Transmission Rate Schedules. BPA may change the rates that apply to Transmission Service under this Service Agreement pursuant to applicable law.

4.2 BILLING AND PAYMENT

Bills for all services provided under this Service Agreement shall be rendered monthly by BPA and shall be payable in accordance with the Tariff.

4.3 BPA APPROPRIATIONS REFINANCING ACT, PUBLIC LAW 104-134

The Transmission Customer and BPA agree that provisions of Section 3201(i) of Public Law 104-134 (BPA Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

ARTICLE 5
NOTICES

5.1 NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice, request, demand, or statement which is given to or made upon either Party by the other Party under any of the provisions of this Service Agreement, except those specified in Article 5.2 below, shall be in writing and shall be considered delivered when either personally delivered to the following or deposited in the mail postage prepaid and properly addressed to the following:

If to the Transmission Customer	If to BPA
Power Exchange Corporation (Powerex) Suite 1400 – 666 Burrard Street Vancouver B.C. V6C 2X8 Attention: Michelle Hiley Phone: (604) 891-5056 Fax: (604) 891-5022	Bonneville Power Administration P. O. Box 491 Vancouver, WA 98666-0491 Attention: Transmission Account Executive for Powerex Phone: (360) 418-2246 Fax: (360) 418-8320

5.2 NOTICES OF AN OPERATING NATURE

Any notice, request, or demand pertaining to matters of an operating nature, exclusive of requests for additional or modified Transmission Service under the Tariff, shall be sufficient if given in writing, by telephone, by facsimile, or orally in person to the person designated in writing by the Party as its representative for such purposes, provided that should such notice, request, or demand not be in

writing, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. The representative for receiving notices pursuant to this Article and such representative's address shall be communicated by the Parties under separate letter within 45 days from the date of execution of this Service Agreement.

ARTICLE 6
MISCELLANEOUS

6.1 INTERCONNECTION WITH OTHER SYSTEMS

Nothing contained in this Service Agreement shall restrict or limit either Party from establishing, altering, or terminating interconnection points with any entity not a party to this Service Agreement or amending or entering into such agreements.

6.2 GOVERNING LAW

This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

6.3 AMENDMENTS

Except as provided in Articles 1.1, 6.4, and 6.5, this Service Agreement may be amended only upon the mutual agreement of the Parties, which amendment shall be reduced to writing and executed by both Parties.

6.4 TARIFF REVISIONS

In the event that BPA proposes to revise the Tariff, either on its own initiative or in response to a directive or order of the Commission, BPA may revise this Service Agreement to remove any irreconcilable differences between this Service Agreement and the proposed revised Tariff, provided that BPA has given the Transmission Customer a copy of the proposed revised Tariff and proposed revised Service Agreement not less than 60 days prior to the date BPA submits such proposed revised Tariff and proposed revised Service Agreement to the Commission for approval, and provided the Commission approves the proposed revised Tariff and proposed revised Service Agreement. Within 30 days of receiving the proposed revised Tariff and proposed revised Service Agreement, the Transmission Customer may provide BPA notice of its intent to terminate this Service Agreement in the event that the Commission approves the revised Service Agreement. If the Transmission Customer provides BPA such notice, and the Commission then approves the revised Service Agreement, the Transmission Customer may terminate this Service Agreement by providing BPA an additional notice of its intent to do so, so long as the Transmission Customer provides such additional notice within 30 days after the effective date of Commission approval of the revised Service Agreement. If the Transmission Customer terminates the Service Agreement pursuant to this Article 6.4, the Transmission Customer shall replace the Transmission Service provided under this Service Agreement by commencing other transmission service under the Tariff.

6.5 REVISION OF EXHIBITS

If any changes to Exhibits A, B, or C are necessary to reflect changes specified below, new exhibits shall be substituted for the exhibits then in effect and shall become effective as of the date specified therein. The Transmission Customer may use the dispute resolution procedures available under the Tariff to challenge such changes.

6.5.1 Subject to the rights and obligations of the Parties as set forth in the Tariff, if the Parties agree to change Exhibit a pursuant to this Service Agreement, BPA shall prepare a revised Exhibit A. BPA reserves the unilateral right to amend contiguous point of delivery provisions in Exhibit A of this Service Agreement.

6.5.2 If the Parties agree to change Exhibit B, BPA shall prepare a new Exhibit B. BPA reserves the right to revise Exhibit B annually to reflect changes consistent with the provisions of Exhibit B, section 1.

6.5.3 If the Parties agree to change Exhibit C, BPA shall prepare a new Exhibit C. BPA reserves the right to update the loss factors identified in Exhibit C, section 2, Transmission Loss Factors.

6.6 TEMPORARY LOAD SHIFTS AND MAINTENANCE NOTIFICATION

The Parties may temporarily interrupt, reduce, or shift deliveries of electric power if any such Party determines that such interruption, reduction, or load shift is necessary or desirable in case of system emergencies or operational constraints on the system of either Party, or to install equipment in, make repairs to, make replacement within, conduct investigations and inspections of, or perform other maintenance work on the Parties' facilities. To the extent reasonable or appropriate, the Parties will use temporary facilities or equipment to minimize the effect of any such interruption, reduction, or load shift.

The Transmission Customer must submit a report concerning any such interruption, reduction, or load shift to BPA within 4 days of such interruption, reduction, or load shift. Reports may be made by telephone, mail, or other electronic processes. The point of contact for each Party will be designated pursuant to Article 5.2 of this Service Agreement. On receipt of the Transmission Customer's report, BPA will adjust the Transmission Customer's billing determinants pursuant to BPA's billing procedures. If the Transmission Customer does not submit the report within 4 days of the interruption, reduction, or load shift, BPA shall assess charges based on available data.

6.7 SEVERABILITY

In the event any of the terms, covenants, or conditions of this Service Agreement, or any amendment hereto, or the application of such terms, covenants, or conditions shall be held invalid as to any Party or circumstance by the Commission or by any court having jurisdiction, all other terms, covenants, and conditions of this Service

Agreement or any amendment hereto, and their application shall remain in full force and effect.

6.8 COMPUTATION OF TIME

To compute any period of time prescribed or allowed by this Service Agreement, the day of the act, event, or default from which the designated period of time begins to run shall not be included. The last day of the period so computed shall be included unless it is a Saturday, Sunday, or legal holiday, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday, or legal holiday. For purposes of the administration of this Service Agreement, Pacific Time shall be used.

6.9 NO THIRD PARTY BENEFICIARIES

This Service Agreement creates rights and obligations only between the Parties hereto. The Parties hereto do not intend to create any obligation or promise of performance to any other person or entity nor have the Parties conferred any right to enforce this Service Agreement or any remedy upon any third person or entity other than the Parties hereto, their respective successors and assigns.

6.10 WAIVERS

Any waiver at any time by either Party of its rights with respect to a default under this Service Agreement, or with respect to any other matter arising in connection with this Service Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter.

6.11 SUCCESSORS AND ASSIGNS

This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

6.12 SERVICE AGREEMENT GOVERNS

In the event of any irreconcilable difference between the Tariff and this Service Agreement, the language of this Service Agreement shall govern.

6.13 ENTIRE AGREEMENT

This Service Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and there are no other understandings or agreements between the Parties with respect hereto.

ARTICLE 7
SIGNATURES

The signatories represent that they are authorized to enter into this Service Agreement on behalf of the Party for whom they sign.

BRITISH COLUMBIA POWER EXCHANGE CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ CLIFFORD C. PERIGO
Name: Murray Margolis (Print/Type)	Name: Clifford C. Perigo (Print/Type)
Title: Head Trader	Title: Senior Transmission Account Executive
Date: 31 May 99	Date: 5-13-99

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Exhibit B
FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

1. USE-OF-FACILITIES COSTS FOR WHICH THE TRANSMISSION CUSTOMER IS RESPONSIBLE

(a) **Calculation of Charges Pursuant to the UFT-96 Rate Schedule**

Facility	Investment [1]	I&A Annual Cost Ratio [2]	I&A Annual Cost	O&M Annual Cost [3]	Sum of Non-Coincidental Demands	$/kW/yr
Substation	$	%	$	$		$
			Total UFT Charge =			$0./kW/mo
			kW to apply UFT charge to:			0 kW

(b) **Changes in Costs and Demands.** BPA may revise Exhibit B annually to reflect changes in: (1) the yearly noncoincidental demands on the facility under this Service Agreement and other agreements; (2) I&A annual cost ratios; (3) O&M annual costs; and (4) investments in facilities.

2. DIRECT ASSIGNMENT FACILITIES CHARGES

none

3. FORMER UFT FACILITIES

---

[1] 199X computation.
[2] Based on ACR table dated _____
[3] Based on O&M table dated _____

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Exhibit C
ANCILLARY SERVICES

1. ANCILLARY SERVICES PROVIDED

		Provided By	Contract No.
(a)	**Scheduling and Dispatch**	BPA (TBL[1/])	99TX-10251
(b)	**Energy Imbalance**	n/a	
(c)	**Control Area Reserves for Resources**	n/a	
(d)	**Control Area Reserves for Interruptible Purchases**	n/a	
(e)	**Load Regulation**	n/a	
(f)	**Reactive Supply and Voltage Control**	BPA (TBL)	99TX-10251
(g)	**Transmission Losses**	Transmission Customer	See Section 5 below

Compensation for Transmission Losses associated with the delivery of power over the FCRTS under this Service Agreement shall be governed by the following provisions:

(1) **Transmission Losses Associated with Federal Power**
Losses associated with Federal power purchased pursuant to BPA's PF-96, NR-96, and IP-96 Wholesale Power and Transmission Rate Schedules are provided by BPA and included in the rate for such power. No additional compensation is required.

(2) **Transmission Losses Associated with Non-Federal Power and Other Classes of Federal Power**
The Transmission Customer shall compensate BPA for losses BPA incurs when providing Transmission Service over the FCRTS for non-Federal power and other classes of Federal power (unless otherwise specified in the Transmission Customer's contract for the purchase of such power), integrated at Points of Interconnection, except those amounts associated with purchases specified in 1(g)(1) above. The compensation shall be determined by multiplying the amount of power delivered under this Service Agreement by the applicable Loss Factor listed below in section 2; and

[1/] BPA's Transmission Business Line.

(A) adding the resulting amount to the billing factor for the Transmission Customer's purchases of Federal power; or

(B) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below; or

(C) Transmission Customer returning the resulting amount to BPA from a single Control Area 168 hours after the time of delivery of power for which loss compensation is required.

(3) **Transmission Losses Associated with Delivery Facilities** Transmission Losses associated with Delivery Facilities shall be determined annually, by Fiscal Year [2/] pursuant to the following procedure:

(A) determining the ratio of power delivered over Delivery Facilities to the total power delivered to the Transmission Customer over the FCRTS; and

(B) multiplying the resulting ratio by the total amount of power delivered to the Transmission Customer less amounts described in 1(g)(1) above; and

(C) multiplying the result derived in step 1(g)(3)(B) by the Delivery Facility loss factor listed below in section 2; and

(D) Transmission Customer purchasing the resulting amount from BPA pursuant to the APS-96 rate schedule (or its successor) for Transmission Losses. The options for purchasing losses (i.e. fixed price, NYMEX) shall be specified in the annual notification letter described in section 1(g)(4)(A) below.

(4) **Notification**

(A) Each Fiscal Year except the Fiscal Year during which this Service Agreement is executed, BPA shall send a letter by August 1 requesting that the Transmission Customer choose one of the methods described in section 1(g)(2). The Transmission Customer shall indicate in the letter its choice

[2/] Fiscal Year is defined as the twelve-month period from October 1 through September 30.

for compensating BPA for transmission losses during the following Fiscal Year, countersign the letter and return one copy to BPA by September 1 of the then current Fiscal Year. The countersigned letter shall serve as the Transmission Customer's confirmation and shall constitute a revision to section 1(g)(5) of Exhibit C.

(B) If the Transmission Customer selects option 1(g)(2)(C) above, the Transmission Customer shall designate in the letter the single Control Area the Transmission Customer will use during the subsequent Fiscal Year.

(C) In the event that, in any Fiscal Year, the Transmission Customer does not notify BPA by September 1 of the method it has chosen, the Transmission Customer's compensation method shall be the method used for the then current Fiscal Year.

(5) **Transmission Customer's Method of Compensation of Annual Transmission Losses during a Fiscal Year**

The Transmission Customer has elected to return Transmission Losses for the period 2400 hours the Date of Execution, 1999, through 2400 hours September 30, 1999. The Transmission Customer will return the losses from a single Control Area in the Pacific Northwest, as defined in the Pacific Northwest Electric Power Planning and Conservation Act. The name of that Control Area is Powerex.

2. TRANSMISSION LOSS FACTORS

Network Loss Factor: 1.9 percent of kWh delivered
ET Loss Factor: 1.9 percent of kWh delivered
Delivery Facility Loss Factor: 0.6 percent of kWh delivered
IS Loss Factor: 3.0 percent of kWh delivered

BPA reserves the right, after consultation with the Transmission Customer, to review the loss methodology and to revise this Exhibit C as appropriate, but not more frequently than once in a 12-month period, to incorporate loss factors which represent then-current FCRTS operating conditions. BPA shall prepare a new Exhibit C incorporating any revision and the revised Exhibit shall become effective as of the date specified therein.

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Department of Energy

Bonneville Power Administration
P.O. Box 491
Vancouver, Washington 98666-0491

TRANSMISSION BUSINESS LINE

AUTHENTICATED
June 13, 2001

In reply refer to: TM/DITT2

Contract No. 99TX-10251
Amendatory Agreement No. 1

Mr. Murray Margolis, Head Trader
Powerex Corp.
Suite 1400, 666 Burrard Street
Vancouver, BC V6C 2X8
Canada

Dear Mr. Margolis:

This letter constitutes Amendment No. 1 (Amendment) to the Firm Point-to-Point Transmission Service Agreement, Contract No. 99TX-10251, (Service Agreement), between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration (BPA), and Powerex Corp. (Transmission Customer).

This Amendment to the Service Agreement acknowledges the Parties' desire to extend the term of the Service Agreement to 2400 hours on June 30, 2021. The Parties agree that all other terms and conditions of the Agreement, as amended, remain the same. Article 3 of the Agreement is hereby amended to read as follows:

> "Service under this Service Agreement shall commence at 2400 hours on June 12, 1999. Service under this Service Agreement shall terminate on the earlier of: (a) 2400 hours on June 30, 2021; or (b) 2400 hours on the date of termination

established pursuant to the Tariff. All liabilities and obligations incurred under this Service Agreement shall be preserved until satisfied."

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for whom they sign.

Sincerely,

Senior Transmission Account Executive

Name Clifford C. Perigo
(Print/Type)

ACCEPTED:

POWEREX CORP.

By: /S/ M. MARGOLIS

Name: Murray Margolis
(Print/Type)

Title: Head Trader

Date: 5 July 01

EXECUTED:

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ CLIFFORD C. PERIGO

Name: Clifford C. Perigo
(Print/Type)

Title: Transmission Account Executive

Effective Date: 7-5-01

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EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

REVISION NO. 4, TABLE 10
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 441996

This Revision No. 4 to Table 10 reflects an assignment of transmission service (see section 3) under this Service Agreement from Assignor Powerex (the Transmission Customer in this Table 10) to Assignee Hermiston Power Partnership (HPP)[1] and is contingent upon execution of such assignment. This Revision No. 4 to Table 10 decreases the Transmission Customer's transmission demand by 100 MW at the John Day Substation POI and the California-Oregon border POD beginning at 0000 hours on April 1, 2002. Such assignment terminates on 2400 hours, June 30, 2021.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on April 1, 2002.
Termination Date: the earlier of (a) 2400 hours on June 30, 2021; or (b) 2400 hours on the termination date established pursuant to Article 3 of this Service Agreement.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

AC Intertie Transmission							
Delivering Party (Resource) [2]	**POI Name & Voltage**	**POI Control Area**	**Maximum POI Demand (kW)**	**POD Name & Voltage**	**POD Control Area**	**Maximum POD Demand (kW)**	**Receiving Party**[2]
	John Day Substation (500 kV)	BPA	See §3 below	COB (500 kV)	CA ISO	See §3 below	Powerex or Designated Agent[3]
DC Intertie Transmission							
	Big Eddy Substation (500 kV)	BPA	See §3 below	NOB (1000 kV)	LDWP	See §3 below	Powerex or Designated Agent [3]

Total Reserved Capacity: See section 3 below.

[1] See Exhibit A, Revision No. 8, of the HPP Service Agreement, Contract No. 98TX-10154.

[2] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

AC Intertie

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	04/01/021 – 06/30/21: 0 MW	IS-02

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	04/01/021 – 06/30/21: 0 MW	IS-02

DC Intertie

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (500 kV)	NOB (1000 kV)	03/01/02 – 06/30/21: 0 MW	IS-02

4. DESCRIPTION OF POINTS OF INTERCONNECTION

(a) **John Day Substation**

Location: the points in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

(b) **Big Eddy Substation**

Location: the points in the Transmission Provider's Big Eddy Substation where the line terminals of the Transmission Provider's Celilo Converter Station are connected to the 500 kV bus;

Voltage: 230/500 kV.

5. POINTS OF DELIVERY

(a) **California-Oregon Border (COB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (ISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

(b) **Nevada-Oregon Border (NOB)**

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon border, where the Transmission Provider shall make electric power available for the Transmission Customer hereunder;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

BRITISH COLUMBIA POWER EXCHANGE CORPORATION

By: /S/ DANNY O'HEARN

Name: **Dan O'Hearn**
(Print/Type)

Title: **Portfolio Manager**

Date: **February 26, 2002**

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: /S/ ROBERT LAHMANN for

Name: Clifford C. Perigo
(Print/Type)

Title: Senior Transmission Account Executive

Date: **3/1/02**

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AUTHENTICATED EXHIBIT A, TABLE 21

REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 386964

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: at 0000 hours on January 1, 2006.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	John Day Substation (500 kV)	BPA	See Sect. 3 Below	COB (500 kV)	CA ISO[2]	See Sect. 3 Below	Powerex or Designated Agent[3]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	01/01/05 – 01/01/06 (42 MW)	IS-02

4. DESCRIPTION OF POINT OF INTERCONNECTION

John Day Substation

Location: the points in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

---

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] California (CA) Independent System Operator (ISO).

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to the Transmission Provider's Transmission Scheduling Provisions.

5. **POINT OF DELIVERY**

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (ISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

IN WITNESS WHEREOF, the Parties have caused this Revision to the Service Agreement to be executed by their respective authorized officials.

BRITISH COLUMBIA POWER EXCHANGE CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ ANTONY T RODRIGUES
Name: Murray Margolis *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
Title: Head Trader	Title: Senior Transmission Account Executive
Date: 6 Jun 03	Date: June 6, 2003

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AUTHENTICATED EXHIBIT A, TABLE 24

REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 786743

1. TERM OF TRANSACTION

Start Date: at 0000 hours on September 1, 2003.
Termination Date: on 0000 hours on September 1, 2006.

This term matches the duration of a competing request that extends through April 1, 2006, and allows the contract to be extended in annual increments. Table 24 combines and replaces Table 12, Table 13 and Table 15, effective September 1, 2002, through September 1, 2003, and extends their termination date. This extension of service is available pursuant to Section 2.2, Reservation Priority for Existing Firm Service Customers, of the Open Access Transmission Tariff (OATT), effective October 1, 2001, which requires that:

> Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	John Day Substation (500 kV)	BPA	See Sect. 3 Below	COB (500 kV)	CA ISO[2]	See Sect. 3 Below	Powerex or Designated Agent[3]

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] California (CA) Independent System Operator (ISO).

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to the Transmission Provider's Transmission Scheduling Provisions.

Total Reserved Capacity	See Sect. 3 Below	See Sect. 3 Below

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	09/01/03 – 9/01/06 (336 MW)	IS-02

The combined capacity demands from Table 12 (200 MW), Table 13 (63 MW), and Table 15 (73 MW) equal 336 MW.

4. DESCRIPTION OF POINT OF INTERCONNECTION

John Day Substation

Location: the points in the Transmission Provider's John Day Substation, where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. POINT OF DELIVERY

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (ISO) hereunder;
Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWEREX CORP. UNITED STATES OF AMERICA

Department of Energy
Bonneville Power Administration

By:	/S/ DOUGLAS LITTLE	By:	/S/ NANCY E MORGAN for
Name: *(Print/Type)*	Douglas Little	Name: *(Print/Type)*	Antony T. Rodrigues
Title:	V.P. Marketing & Trade Policy	Title:	Senior Transmission Account Executive
Date:	Aug 5/03	Date:	7-25-03

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 25
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 825197

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: on 0000 hours on January 1, 2006.

The Transmission Customer and the Transmission Provider agree to the following conditions:

(a) Amendment No. 1 to Agreement No. 99TX-10230 and Revision No. 1 to Exhibit A of the Agreement: The Transmission Customer shall execute Amendment No. 1 to Agreement No. 99TX-10230 (Agreement) and Revision No. 1 to Exhibit A of the Agreement, which extend the termination date of the Agreement from August 31, 2003, to August 31, 2004, and designate 194 MW as the amount of reservation priority (rollover) rights available under the Agreement. Furthermore, the Transmission Customer agrees to waive its reservation priority (rollover) rights.

(b) Reservation Priority (Rollover) Rights for Table 4a to Exhibit A of Agreement No. 99TX-10251: The Transmission Customer agrees that Table 4a to Agreement No. 99TX-10251 does not have reservation priority (rollover) rights as described in Section 2.2 of the Open Access Transmission Tariff, pursuant to Section 3.2 of the TR-02/TC-02 Settlement Agreement, dated June 20, 2000.

(c) Table 22 and Table 23 to Exhibit A of Agreement No. 99TX-10251: The Transmission Customer shall unconditionally reject the offers for transmission service made by the Transmission Provider in Table 22 and Table 23 to Agreement 99TX-10251, dated June 30, 2003. The Transmission Provider will remove in their entirety from the long-term queue both of the Transmission Customer's requests, which were assigned OASIS Queue No. 664 and OASIS Queue No. 665, respectively, for the service from Big Eddy to Nevada-Oregon Border (NOB) associated with these offers.

(d) Transmission Requests, OASIS Queue Nos. 658, 663, 667, 668, 670, and 671: The Transmission Customer shall withdraw the following transmission requests for service from Big Eddy to NOB: OASIS Queue Nos. 658, 663, 667, 668, 670, and 671.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	01/01/05 – 01/01/06 408 MW	IS-02

Remainder of 1,000 MW Request: The maximum capacity requested is 1,000 MW, and due to insufficient capacity the transmission demand under this Table 25 is limited to 408 MW. The remainder of the capacity of 592 MW will remain in the queue until December 31, 2005.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

---

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

5. **POINTS OF DELIVERY**

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ ANTONY RODRIGUES
Name: **Murray Margolis** *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
Title: **Head Trader**	Title: Senior Transmission Account Executive
Date: **Sep 10, 2003**	Date: **August 22, 2003**

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 26
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 825204

1. TERM OF TRANSACTION

Start Date: at 0000 hours on June 1, 2005.
Termination Date: on 0000 hours on June 1, 2006.

The Transmission Customer and the Transmission Provider agree to the following conditions:

(a) Table 25 to Exhibit A of Agreement No. 99TX-10251: The Transmission Customer shall execute Table 25 to Exhibit A of Agreement No. 99TX-10251, and agree to the terms and conditions included therein.

(b) Transmission Request, OASIS Queue No. 672-01: The Transmission Customer shall withdraw its transmission request for service from Big Eddy to NOB, which was assigned OASIS Queue No. 672-01.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	06/01/05 – 06/01/06 150 MW	IS-02

Remainder of 1,000 MW Request: The maximum capacity requested is 1,000 MW, and due to insufficient capacity the transmission demand under this Table 26 is limited to 100 MW. The remainder of the capacity of 850 MW will remain in the queue until May 31, 2006.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ ANTONY T RODRIGUES
Name: Murray Margolis *(Print/Type)*	Name: Antony T. Rodrigues *(Print/Type)*
Title: Head Trader	Title: Senior Transmission Account Executive
Date: Sep 10, 2003	Date: August 22, 2003

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE
TABLE 29
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 885874

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: on 0000 hours on January 1, 2006.

The Transmission Customer and the Transmission Provider agree to the following condition:

Revision No. 2, Table 17 to Exhibit A of Agreement No. 99TX-10251: Prior to executing Table 29, the Transmission Customer shall execute Revision No. 2, Table 17 to Exhibit A of Agreement No. 99TX-10251.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource)[1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	01/01/05 – 01/01/06 49 MW	IS-02

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

Remainder of 1,000 MW Request: The maximum capacity requested under Oasis Request No. 672 is 1,000 MW. Due to insufficient capacity, a partial award of 408 MW was made under Table 25, and the transmission demand under this Table 29 is limited to 49 MW. The remainder of the capacity of 543 MW will remain in the queue, unless awarded, until January 2, 2005.

4. **DESCRIPTION OF POINTS OF INTERCONNECTION**

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

5. **POINTS OF DELIVERY**

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

POWEREX CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ THOMAS M NOGUCHI
Name: Murray Margolis *(Print/Type)*	Name: Thomas M. Noguchi *(Print/Type)*
Title: Head Trader	Title: Senior Transmission Account Executive
Date: 29 Oct 03	Date: 10/16/03

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EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 40
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1349205.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on June 1, 2005.
Termination Date: at 0000 hours on June 1, 2007.

The Transmission Provider's offer of transmission service to the Transmission Customer under this Table 40 in Exhibit A to Service Agreement No. 99TX-10251 (Service Agreement) is contingent upon the choice the Transmission Customer makes with regard to its section 2.2 reservation priority (rollover) rights associated with Table 32, which is also under this Service Agreement. These reservation priority rights are provided for in the Transmission Provider's Open Access Transmission Tariff.

If the Transmission Customer agrees to accept a contract term for the rollover of Table 32 that is at least equal to the term in this Table 40, then this Table 40 will be null and void.

If the Transmission Customer refuses to accept a contract term for the rollover of Table 32 that is at least equal to the term in this Table 40, or permanently releases capacity sufficient to provide for the transmission service in this Table 40, then Table 40 will be fully operational as of its effective date of June 1, 2005.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY.

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	06/01/05 – 06/01/07 250 MW	IS-04

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ NANCY E MORGAN
Name: Murray Margolis *(Print/Type)*	Name: Nancy E. Morgan *(Print/Type)*
Title: Head Trader	Title: Acting Transmission Sales Manager
Date: 17 Nov 04	Date: 11-1-04

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 41
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1356130.

1. TERM OF TRANSACTION

Start Date: at 0000 hours on January 1, 2005.
Termination Date: at 0000 hours on January 1, 2007.

This term is extended to match the duration of a competing request whose term runs for two years. This extension of the term of service is required pursuant to Section 2.2, Reservation Priority for Existing Firm Service Customers, of the Open Access Transmission Tariff (OATT), effective October 1, 2001, which provides that:

> Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	Big Eddy Substation (230/500 kV)	BPA	See Sect. 3 Below	NOB (1000 kV)	LDWP	See Sect. 3 Below	Powerex or Designated Agent[2]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
Big Eddy Substation (230/500 kV)	NOB (1000 kV)	01/01/05 – 01/01/07 650 MW	IS-04

4. DESCRIPTION OF POINTS OF INTERCONNECTION

Big Eddy Substation

Location: the points in BPA's Big Eddy Substation, where the line terminals of BPA's Celilo DC Converter Station are connected to the 230 kV and 500 kV busses;

Voltage: 230/500 kV;

Metering: quantities are to be scheduled.

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

5. **POINTS OF DELIVERY**

Nevada-Oregon Border (NOB)

Location: on the Pacific Northwest-Pacific Southwest Intertie, near the Nevada-Oregon Border (NOB), where BPA shall make electric power available for the Transmission Customer;

Voltage: 1,000 kV;

Metering: quantities are to be scheduled.

6. **DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION**
Transmission Customer and its affiliate (if they own transmission facilities).

7. **NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE**
None.

POWER EXCHANGE CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ DOUGLAS LITTLE	By: /S/ NANCY E MORGAN
Name: Douglas Little *(Print/Type)*	Name: Nancy E. Morgan *(Print/Type)*
Title: V.P. Marketing & Trade Policy	Title: Acting Transmission Sales Manager
Date: Dec 1/04	Date: 11-19-04

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AUTHENTICATED

EXHIBIT A
STATEMENT OF SPECIFICATIONS FOR LONG-TERM FIRM TRANSMISSION SERVICE

TABLE 43
REQUEST FOR TRANSMISSION SERVICES

The OASIS Assignment Reference Number (ARef) is: 1400275

1. TERM OF TRANSACTION

Start Date: at 0000 hours on March 1, 2005.
Termination Date: at 0000 hours on July 1, 2006.

This is an award of partial service, since as of the execution date of this Agreement, the Transmission Provider does not have sufficient transmission capacity to accommodate Point-to-Point Transmission Service to the Transmission Customer beyond the Termination Date. Therefore, the Transmission Customer shall not have the right defined in section 2.2 of the Tariff, to continue to take Point-to-Point Transmission Service from the Transmission Provider after the Termination Date listed above.

2. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY/DELIVERING PARTY/CONTROL AREA/RECEIVING PARTY/SCHEDULING AGENT

Delivering Party (Resource) [1]	POI Name & Voltage	POI Control Area	Maximum POI Demand (kW)	POD Name & Voltage	POD Control Area	Maximum POD Demand (kW)	Receiving Party[1]
	John Day Substation (500 kV)	BPA	See Sect. 3 Below	COB (500 kV)	CAISO [2]	See Sect. 3 Below	Powerex or Designated Agent[3]
Total Reserved Capacity			See Sect. 3 Below			See Sect. 3 Below	

[1] If the Delivering Party, Resource or Receiving Party is not known at the time of application, the Transmission Customer or its Scheduling Agent shall identify the Delivering Party, Resource and Receiving Party at the time of preschedule and or real time.

[2] California Independent System Operator (CAISO)

[3] A single designated scheduling agent will act in all capacities for the Transmission Customer pursuant to BPA's Transmission Scheduling Provisions.

3. SUMMARY OF POINTS OF INTERCONNECTION AND POINTS OF DELIVERY

Point(s) of Interconnection (Voltage)	Point(s) of Delivery (Voltage)	Transmission Demand (MW)	Rate
John Day Substation (500 kV)	COB (500 kV)	03/01/05 – 07/01/06 50 MW	IS-04

Remainder of 100 MW Request: The maximum capacity requested under Oasis Request No. 800 is 100 MW, starting on January 1, 2005, and ending on January 1, 2009. Due to insufficient capacity the transmission demand under this Table 43 is limited to 50 MW, and only for the period commencing on March 1, 2005, and terminating on July 1, 2006. The partial capacity award of 50 MW will be reinstated to the OASIS Long-Term Queue on July 2, 2006.

4. DESCRIPTION OF POINTS OF INTERCONNECTION

John Day Substation

Location: the points in the Transmission Provider's John Day Substation where the line terminals of the Pacific AC Intertie are connected to the 500 kV bus;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

5. POINTS OF DELIVERY

California-Oregon Border (COB)

Location: the point on the Pacific Northwest-Pacific Southwest Intertie, near the California-Oregon border, where the Transmission Provider shall make electric power available for the California Independent System Operator (CAISO) hereunder;

Voltage: 500 kV;

Metering: quantities are to be scheduled.

6. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliate (if they own transmission facilities).

7. NAME(S) OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

POWEREX CORP.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: /S/ MURRAY MARGOLIS	By: /S/ DAVID A FITZSIMMONS
Name: **Murray Margolis** *(Print/Type)*	Name: David A. Fitzsimmons *(Print/Type)*
Title: **Head Trader**	Title: Transmission Account Executive
Date: **2/17/05**	Date: **2/3/05**

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